161 FERC ¶ 61,042
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Neil Chatterjee, Chairman;
Cheryl A. LaFleur, and Robert F. Powelson.

Atlantic Coast Pipeline, LLC	Docket Nos. CP15-554-000 CP15-554-001
Dominion Transmission, Inc.	CP15-555-000
Atlantic Coast Pipeline, LLC Piedmont Natural Gas Company, Inc.	CP15-556-000

ORDER ISSUING CERTIFICATES

(Issued October 13, 2017)

1. On September 18, 2015, Atlantic Coast Pipeline, LLC (Atlantic) filed an application in Docket No. CP15-554-000, pursuant to section 7(c) of the NGA[1] and Part 157 of the Commission's regulations,[2] for authorization to construct and operate the Atlantic Coast Pipeline Project (ACP Project). On March 11, 2016, Atlantic filed an amendment to its application in Docket No. CP15-554-001. In its amendment, Atlantic proposed several route changes and additional compression at its proposed compressor station in Buckingham County, Virginia. The ACP Project, as amended, consists of approximately 604 miles of new interstate pipeline and related facilities extending from Harrison County, West Virginia, to the eastern portions of Virginia and North Carolina,[3] and 130,345 horsepower (hp) of compression. The ACP Project is designed to provide up to 1.5 million dekatherms per day (Dth/d) of natural gas transportation service. Atlantic also requests approval of its *pro forma* tariff, a blanket certificate under Part 284,

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[1] 15 U.S.C. § 717f(c) (2012).

[2] 18 C.F.R. pt. 157 (2017).

[3] The ACP Project extends from West Virginia, southeast to Greensville County, Virginia, then splits into two legs; one leg extending east to the City of Chesapeake, Virginia, and the other leg extending southwest into North Carolina.

Subpart G of the Commission's regulations to provide open-access transportation services, and a blanket certificate under Part 157, Subpart F of the Commission's regulations to perform certain routine construction activities and operations.

2. On September 18, 2015, Dominion Transmission, Inc. (DETI)[4] filed an application in Docket No. CP15-555-000, under sections 7(b) and 7(c) of the NGA[5] and Part 157 of the Commission's regulations,[6] requesting authorization to construct and operate approximately 38 miles of pipeline looping facilities and other facility upgrades and modifications to DETI's existing system in Pennsylvania and West Virginia (Supply Header Project). The Supply Header Project is designed to provide up to 1,511,335 Dth/d of natural gas transportation service from supply areas on the DETI system to the proposed ACP Project. DETI also requests authorization to abandon two previously-certificated gathering compressor units in Wetzel County, West Virginia.

3. Also, on September 18, 2015, Atlantic and Piedmont Natural Gas Company, Inc. (Piedmont) filed a joint application in Docket No. CP15-556-000, pursuant to section 7(c) of the NGA[7] and Part 157 of the Commission's regulations,[8] for approval of a lease pursuant to which Atlantic will lease 100,000 Dth/d of capacity on Piedmont's system for use by Atlantic in providing service under Atlantic's FERC Gas Tariff (Capacity Lease). Additionally, Piedmont requests a limited jurisdiction certificate to carry out its responsibilities under the lease agreement.

4. As explained herein, we find that the benefits that the ACP Project, Supply Header Project, and Capacity Lease will provide to the market outweigh any adverse effects on existing shippers, other pipelines and their captive customers, and on landowners and surrounding communities. Further, as set forth in the environmental discussion below, we agree with Commission staff's conclusion in the Environmental Impact Statement (EIS) that, if constructed and operated in accordance with applicable laws and regulations and with the implementation of the applications' proposed mitigation and staff's recommendations, now adopted as conditions in the attached Appendix A of this order, the projects will result in some adverse and significant environmental impacts, but that

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[4] On May 12, 2017, Dominion Transmission, Inc. changed its name to Dominion Energy Transmission, Inc.

[5] 15 U.S.C. § 717f(b) and (c) (2012).

[6] 18 C.F.R. pt. 157 (2017).

[7] 15 U.S.C. § 717f(c) (2012).

[8] 18 C.F.R. pt. 157 (2017).

these impacts will be reduced to acceptable levels. Therefore, we grant the requested authorizations, subject to conditions.

I. Background

5. Atlantic, a limited liability company organized and existing under the laws of Delaware, was formed to develop, own, and operate the ACP Project and does not currently own any existing pipeline facilities and is not engaged in any natural gas operations. Atlantic is composed of four ownership interests: Dominion Atlantic Coast Pipeline, LLC, a Delaware limited liability company and subsidiary of Dominion Resources, Inc. (48 percent ownership); Duke Energy ACP, LLC, a Delaware limited liability company and subsidiary of Duke Energy Corporation (40 percent ownership); Piedmont ACP Company, LLC, a North Carolina limited liability company and subsidiary of Duke Energy Corporation (7 percent ownership);[9] and Maple Enterprise Holdings, Inc., a Georgia corporation and subsidiary of The Southern Company[10] (5 percent ownership).[11] Upon commencing the operations proposed in its application, Atlantic will become a natural gas company within the meaning of section 2(6) of the NGA[12] and will be subject to the Commission's jurisdiction.

6. DETI, a Delaware corporation,[13] is a natural gas company, as defined in section 2(6) of the NGA.[14] DETI provides natural gas transportation and storage services in Ohio, West Virginia, Pennsylvania, New York, Maryland, and Virginia.

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[9] On October 3, 2016, Duke Energy Corporation purchased Piedmont Natural Gas Company, Inc. and became the parent company of Piedmont ACP Company, LLC. Effective on October 3, 2016, Piedmont ACP Company, LLC assigned 3 percent of its original 10 percent ownership interest in Atlantic to Dominion Atlantic Coast Pipeline, LLC.

[10] The Southern Company merged with AGL Resources Inc. in a transaction that closed on July 1, 2016.

[11] *See* Atlantic February 28, 2017 Data Response.

[12] 15 U.S.C. § 717a(6) (2012).

[13] DETI is wholly-owned subsidiary of Dominion Gas Holdings, LLC, which, in turn, is a wholly-owned subsidiary of Dominion Resources, Inc.

[14] 15 U.S.C. § 717a(6) (2012).

7. Piedmont, a North Carolina corporation, is a local distribution company primarily engaged in the distribution of natural gas to residential, commercial, and industrial utility customers in North Carolina, South Carolina, and Tennessee. Piedmont is a "public utility" under Chapter 62 of the North Carolina General Statutes and its North Carolina rates and services are regulated by the North Carolina Utility Commission (NCUC).

II. Proposals

A. Atlantic Coast Pipeline Project

1. Facilities and Services

8. The ACP Project, as amended, consists of two mainlines, three lateral lines, three compressor stations, and nine metering and regulating (M&R) stations. Generally, the ACP Project will receive natural gas at the terminus of the Supply Header Project's TL-635 Loop in Harrison County, West Virginia, and transport up to 1.5 million Dth/d to receipt points in West Virginia, Virginia, and North Carolina. The ACP Project will involve the construction of the following facilities:

- approximately 333.1 miles of 42-inch-diameter mainline pipeline originating in Harrison County, West Virginia, and terminating at the location of the proposed Compressor Station 3 in Northampton County, North Carolina (AP-1 Mainline);

- approximately 186.0 miles of 36-inch-diameter mainline pipeline originating at Compressor Station 3 in Northampton County, North Carolina, and terminating at the existing Piedmont pipeline system in Robeson County, North Carolina (AP-2 Mainline);

- approximately 83.2 miles of 20-inch-diameter lateral pipeline originating at Compressor Station 3 in Northampton County, North Carolina, and extending east to an interconnect with the existing Virginia Natural Gas pipeline system in the City of Chesapeake, Virginia (AP-3 Lateral);

- approximately 0.4 miles of 16-inch-diameter lateral pipeline originating at an interconnect point with the AP-1 Mainline near Lawrenceville in Brunswick County, Virginia, and extending west to Dominion Virginia Power's Brunswick Power Station (AP-4 Lateral);

- approximately 1.0 miles of 16-inch-diameter lateral pipeline originating at an interconnect point with the AP-1 Mainline in Greensville County, Virginia, and extending to Dominion Virginia Power's proposed Greensville Power Station (AP-5 Lateral);

- a new compressor station consisting of four natural gas-fired, turbine-driven units, one 20,500 hp unit, one 15,900 hp unit, one 10,915 hp unit, and one 7,700 hp unit, for a total of 55,015 hp, located near milepost (MP) 7.6 of the AP-1 mainline at the proposed Kincheloe M&R station in Lewis County, West Virginia (Compressor Station 1 or Marts Compressor Station);

- a new compressor station consisting of four natural gas-fired, turbine-driven units, one 20,500 hp unit, one 15,900 hp unit, one 10,915 hp unit, and one 6,200 hp unit, for a total of 53,515 hp, located near MP 191.5 of the AP-1 mainline in Buckingham County, Virginia (Compressor Station 2 or Buckingham Compressor Station);

- a new compressor station consisting of three natural gas-fired, turbine-driven units, one 10,915 hp unit, one 6,200 hp unit, and one 4,700 hp unit, for a total of 21,815 hp, located near MP 300.1 of the AP-1 mainline in Northampton County, North Carolina (Compressor Station 3 or Northampton Compressor Station);

- nine new meter stations in West Virginia, Virginia, and North Carolina; and

- various appurtenances.

Atlantic estimates that the proposed facilities will cost $5,071,226,515.

9. Atlantic states that it conducted a non-binding open season from April 16, 2014, to May 9, 2014, for the proposed firm transportation services offered by the project. Atlantic executed binding precedent agreements with the following six shippers for a total of 1.44 million Dth/d of firm transportation service: (1) Duke Energy Progress, LLC (Duke Energy Progress);[15] (2) Duke Energy Carolinas, LLC (Duke Energy Carolinas);[16] (3) Piedmont;[17] (4) Virginia Power Services Energy Corp., Inc.;[18] (5) Public

[15] Duke Energy Progress, an electricity generator and provider, is a subsidiary of Duke Energy Corporation, which has a 47 percent ownership in Atlantic through its subsidiaries.

[16] Duke Energy Carolinas, an electricity generator and provider, is also a subsidiary of Duke Energy Corporation.

[17] As stated above, on October 3, 2016, Duke Energy Corporation purchased Piedmont.

Service Company of North Carolina, Inc.;[19] and (6) Virginia Natural Gas Company, Inc.[20] Atlantic also conducted a binding open season from October 21, 2014, to November 10, 2014, and no additional customers executed binding precedent agreements.

10. Atlantic also requests approval of its proposed *pro forma* tariff. Atlantic proposes initial maximum and minimum recourse reservation and usage rates set forth under Rate Schedules FT (Firm Transportation Service) and IT (Interruptible Transportation Service).

2. Blanket Certificates

11. Atlantic requests a Part 284, Subpart G blanket certificate of public convenience and necessity pursuant to section 284.221 of the Commission's regulations, authorizing Atlantic to provide transportation service to customers requesting and qualifying for transportation service under its proposed FERC Gas Tariff, with pre-granted abandonment authorization.[21]

12. Atlantic also requests a blanket certificate of public convenience and necessity, pursuant to section 157.204 of the Commission's regulations, authorizing future facility construction, operation, and abandonment as set forth in Part 157, Subpart F of the Commission's regulations.[22]

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[18] Virginia Power Services Energy Corp., Inc. is a subsidiary of Virginia Electric and Power Company, which is a subsidiary of Dominion Resources, Inc. Dominion Resources, Inc. has a 48 percent ownership interest in Atlantic through its subsidiaries. Virginia Power Services Energy Corp., Inc. provides fuel, including natural gas, to Dominion's affiliates.

[19] Public Service Company of North Carolina, Inc., a local distribution company, is a subsidiary of SCANA Corporation and has no affiliation with the ACP Project's sponsors.

[20] Virginia Natural Gas Company, Inc., a local distribution company, is a subsidiary of The Southern Company, which has a five percent ownership interest in Atlantic through Maple Enterprise Holdings, Inc.

[21] 18 C.F.R. § 284.221 (2017).

[22] 18 C.F.R. § 157.204 (2017).

B. DETI Supply Header Project

13. DETI proposes to construct and operate the Supply Header Project, which will provide 1,511,335 Dth/d of transportation service from supply areas on DETI's system to the upstream end of the ACP Project in Harrison County, West Virginia. Specifically, DETI proposes to construct:

- approximately 3.9 miles of 30-inch-diameter pipeline that will loop DETI's existing LN-25 pipeline and connect with DETI's existing TL-591 pipeline in Westmoreland County, Pennsylvania (TL-636 Loop);
- approximately 33.6 miles of 30-inch-diameter natural gas pipeline that will loop DETI's existing TL-360 pipeline in Harrison, Doddridge, Tyler, and Wetzel Counties, West Virginia (TL-635 Loop);
- one 20,500 hp natural gas-fired, turbine-driven compressor unit and ancillary equipment at DETI's existing JB Tonkin Compressor Station in Westmoreland County, Pennsylvania;
- one 7,700 hp natural gas-fired, turbine-driven compressor unit and ancillary equipment at DETI's existing Crayne Compressor Station in Greene County, Pennsylvania;
- two 20,500 hp natural gas-fired, turbine-driven compressor units and ancillary equipment at DETI's existing Mockingbird Hill Compressor Station in Wetzel County, West Virginia; and
- six valve sites and two sets of pig launcher and receiver sites.

14. Additionally, DETI requests authorization to abandon Compressor Units 1 and 2 at its Hastings Compressor Station in Wetzel County, West Virginia. DETI states that, in 2006, the Commission approved the refunctionalization of the compressor units from transmission to gathering, but because DETI intended to continue to use the compressor units, the Commission explained that DETI would need to seek abandonment authority from the Commission in the future as necessary.[23] DETI proposes to replace Hastings Compressor Units 1 and 2 with new, more efficient units that will meet the applicable

[23] *Dominion Transmission, Inc.*, 114 FERC ¶ 61,266 (2006).

state and federal air quality requirements.[24] DETI asserts that the replacement units will continue to serve a non-jurisdictional function.

15. The total estimated cost for the Supply Header Project is $486,388,831. DETI conducted a binding open season between October 21, 2014, and November 17, 2014, for the Supply Header Project's proposed firm transportation services.[25] As a result of the open season, DETI executed a binding precedent agreement with Atlantic for 1,450,882 Dth/d of firm transportation service. DETI and Atlantic have entered into a negotiated rate agreement for service on the Supply Header Project.

C. Atlantic's Lease of Capacity on Piedmont's System

16. Atlantic and Piedmont seek approval of a lease, pursuant to which Atlantic will lease capacity on Piedmont's system for use by Atlantic in providing service under Atlantic's FERC Gas Tariff, principally for Public Service Company of North Carolina, Inc. (PSNC). Specifically, Atlantic would lease 100,000 Dth/d on Piedmont's system from the point of interconnection between the ACP Project and Piedmont in Johnson County, North Carolina, to a delivery point between Piedmont and PSNC near Clayton, North Carolina. The Capacity Lease would continue for a primary term of 20 years, consistent with the term of Atlantic's precedent agreement with PSNC.

17. The Capacity Lease requires Atlantic to pay Piedmont a monthly lease charge for the leased capacity. The leased capacity will be treated as part of Atlantic's system for nomination and scheduling purposes, with points identified and made available on Atlantic's electronic scheduling system. Atlantic and Piedmont state that the Capacity Lease will allow Atlantic to provide service to PSNC (or any other customer that may take service off the capacity leased on Piedmont's system) without requiring a direct interconnect between the ACP Project and PSNC's system, thus avoiding the need for the additional construction and environmental disturbance that would be associated with extending the ACP Project to PSNC's system.

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[24] DETI states that the proposed units at its Mockingbird Hill Compressor Station will be included in the same Title V air permit as DETI's Hastings Compressor Station and Lewis Wetzel Compressor Station. DETI asserts that its initial design studies indicated that the additional compression needed for the Supply Header Project could potentially exceed air quality limits unless the two 500 hp Hasting Compressor units are replaced.

[25] DETI states that it conducted a reverse open season during the same time period but received no bids in response.

18. Piedmont also requests a limited jurisdiction certificate in order to enter into the Capacity Lease with Atlantic to allow for the interstate transportation of natural gas through Piedmont's facilities. Last, Piedmont seeks a determination that the Capacity Lease will not affect its status as a local distribution company not otherwise subject to Commission jurisdiction.

III. Procedural Issues

A. Notice, Interventions, Protests, and Comments

19. Notice of applications in Docket Nos. CP15-554-000, CP15-555-000, and CP15-556-000 was published in the *Federal Register* on October 8, 2015 (80 Fed. Reg. 60,886). Notice of the amendment to Atlantic's application in Docket No. CP15-554-001 was published in the *Federal Register* on March 31, 2016 (81 Fed. Reg. 18,623). In each docket, a number of timely and late motions to intervene were filed.[26] Timely, unopposed motions to intervene are granted automatically pursuant to Rule 214 of the Commission's Rules of Practice and Procedure.[27] On November 8, 2016, and January 18, 2017, the Commission issued notices granting numerous late motions to intervene. We grant the remaining unopposed late motions to intervene.[28]

20. Numerous landowners and environmental groups filed protests in response to Atlantic's and DETI's applications. The NCUC protested certain rate and tariff proposals. On December 4, 2015, Atlantic and DETI filed a joint answer to the protests. Shenandoah Valley Network, Friends of the Central Shenandoah, and Friends of Wintergreen filed answers in response to Atlantic and DETI's Answer. Although the Commission's Rules of Practice and Procedure generally do not permit answers to protests or answers to answers,[29] our rules also provide that we may, for good cause, waive this provision.[30] We will accept all the responsive pleadings filed in this

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[26] The Commission's regulations provide that interventions are timely if filed during the comment period on the notice of the application or if filed on environmental grounds during the comment period of the draft EIS. 18 C.F.R. §§ 157.10, 380.10(a), 385.214(c) (2017). Thus, if interventions are filed outside of these periods, the intervention is late. *See Florida Southeast Connection, LLC*, 154 FERC ¶ 61,080, at P 40 n.13 (2016).

[27] 18 C.F.R. § 385.214(c) (2017).

[28] 18 C.F.R. § 385.214(d) (2017).

[29] 18 C.F.R. § 385.213(a)(2) (2017).

[30] 18 C.F.R. § 385.101(e) (2017).

proceeding because they have provided information that assisted us in our decision-making process.

21. In addition, we received numerous comments in support of the ACP Project, asserting it would, among other things, bring jobs to the area, increase economic growth, and provide affordable natural gas supplies to consumers, and a large number of comments raising concerns over the need for and the environmental impacts of the proposed projects. These concerns are addressed in the EIS and below.

B. Request for Evidentiary Hearing

22. Some interveners and commenters object to Atlantic's use of shortened procedures pursuant to Rules 801 and 802 of the Commission's Rules of Practice and Procedure,[31] and request an evidentiary hearing. Conservation Groups[32] argue that allegations concerning the need for the proposed projects cannot be resolved on the basis of the written record. In its June 21, 2017 Motion for an Evidentiary Hearing, Conservation Groups aver that the disputed facts will depend on live testimony from multiple, conflicting experts offering opinions on complex technical issues related to pipeline financing, electricity demand forecasting, existing pipeline capacity, and renewable energy forecasting. Conservation Groups state that expert testimony and cross examination is essential for the Commission to effectively evaluate the credibility and reliability of each witness.

23. Section 7 of the NGA provides for a hearing when an applicant seeks a certificate of public convenience and necessity, but does not require that all such hearings be formal, trial-type hearings.[33] An evidentiary trial-type hearing is necessary only when there are material issues of fact in dispute that cannot be resolved on the basis of the written record.[34] The issues raised in this proceeding, including those concerning the need for the proposed projects, have been adequately argued, and a determination can be made on the basis of the existing record in this proceeding. All interested parties have been

[31] 18 C.F.R. §§ 385.801 and 385.802 (2017).

[32] Conservation Groups are Shenandoah Valley Network, Highlanders for Responsible Development, Virginia Wilderness Committee, Shenandoah Valley Battlefields Foundation, Natural Resources Defense Council, Cowpasture River Preservation Association, Friends of Buckingham, and Winyah Rivers Foundation.

[33] *Dominion Transmission, Inc.*, 141 FERC ¶ 61,240, at P 25 (2012).

[34] *See, e.g., Southern Union Gas Co. v. FERC*, 840 F.2d 964, 970 (1988); *Dominion Transmission, Inc.*, 141 FERC ¶ 61,183, at P 15 (2012).

afforded a full complete opportunity to present their views to the Commission through numerous written submissions. We find that there is no material issue of fact that we cannot resolve on the basis of the written record in the proceeding. Therefore, we will deny the request for a formal, trial-type hearing.

IV. Discussion

24. Since the proposed facilities will be used to transport natural gas in interstate commerce, subject to the jurisdiction of the Commission, the construction and operation of the facilities are subject to the requirements of subsections (c) and (e) of section 7 of the NGA.

A. Application of Certificate Policy Statement

25. The Certificate Policy Statement provides guidance for evaluating proposals to certificate new pipeline construction.[35] The policy statement establishes criteria for determining whether there is a need for a proposed project and whether the proposed project will serve the public interest. It explains that, in deciding whether to authorize the construction of major new facilities, the Commission balances the public benefits against the potential adverse consequences. The Commission's goal is to give appropriate consideration to the enhancement of competitive transportation alternatives, the possibility of overbuilding, subsidization by existing customers, the applicant's responsibility for unsubscribed capacity, the avoidance of unnecessary disruptions of the environment, and the unneeded exercise of eminent domain in evaluating new pipeline construction.

26. Under this policy, the threshold requirement for pipelines proposing new projects is that the pipeline must be prepared to financially support the project without relying on subsidization from its existing customers. The next step is to determine whether the applicant has made efforts to eliminate or minimize any adverse effects the project might have on the applicant's existing customers, existing pipelines in the market and their captive customers, and landowners and communities affected by the route of the new pipeline. If residual adverse effects on these interest groups are identified after efforts have been made to minimize them, the Commission will evaluate the project by balancing the evidence of public benefits to be achieved against the residual adverse effects. This is essentially an economic test. Only when the benefits outweigh the adverse effects on economic interests will the Commission proceed to complete the environmental analysis where other interests are considered.

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[35] *Certification of New Interstate Natural Gas Pipeline Facilities*, 88 FERC ¶ 61,227 (1999), *clarified*, 90 FERC ¶ 61,128, *further clarified*, 92 FERC ¶ 61,094 (2000) (Certificate Policy Statement).

1. Atlantic Coast Pipeline Project

a. Subsidization and Impacts on Existing Customers

27. As discussed above, the threshold requirement for pipelines proposing new projects is that the pipeline must be prepared to financially support the project without subsidization from existing customers. Friends of the Central Shenandoah argue that because a subsidiary and parent are one unit,[36] the ACP Project is subsidized by the affiliated shippers' captive ratepayers. Friends of the Central Shenandoah assert that lower cost options for natural gas transportation are available and these affiliated shippers will pass on the higher costs of the ACP Project to their ratepayers.

28. The Commission's test regarding subsidization analyzes the impacts on existing customers of the pipeline, not customers of the affiliated shippers.[37] Atlantic is a new pipeline entrant with no existing customers. Thus, there is no potential for subsidization on Atlantic's system or degradation of service to existing customers. Issues concerning proposed service to affiliated shippers are discussed more fully below.

b. Need for the Project

29. Several parties and commenters challenged the need for the ACP Project. They raise a variety of arguments including: (1) the availability of existing infrastructure to serve markets; (2) insufficient demand for natural gas in Virginia and North Carolina; (3) insufficient production growth in the Appalachian Basin; (4) the availability of renewable energy to meet future demand for electricity generation; (5) the need for a regional analysis to determine if the project is needed; and (6) the use of precedent agreements with affiliated utilities to demonstrate project need. The commenters also challenged the studies submitted by Atlantic showing that the project is needed to serve demand growth in Virginia and North Carolina. On December 4, 2015, Atlantic filed an answer to the initial comments.[38]

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[36] Friends of the Central Shenandoah cite *Copperweld Corp. v. Independence Tube Corp.*, 467 U.S. 752 (1984), where the Court stated that a subsidiary and its parent are "in reality, one unit." Friends of the Central Shenandoah April 3, 2017 Comments at 11.

[37] Certificate Policy Statement, 88 FERC at 61,745.

[38] Atlantic's answer was filed in response to comments made during the initial notice of application comment period. Since that time, additional comments related to the need for the proposed project have been filed. All comments concerning project need are addressed here.

i. Existing Infrastructure to Serve Markets

30. Commenters argue that there is not currently a supply constraint in the region and that there is adequate natural gas infrastructure to serve future market demand in Virginia and North Carolina. Commenters assert that a study conducted by Synapse Energy Economics Inc. (Synapse),[39] which compares the region's existing natural gas supply capacity to its expected future peak demand for natural gas, concluded that, given the existing pipeline and natural gas storage capacity, the expected flow reversal on the Transcontinental Gas Pipe Line Company, LLC (Transco) pipeline system under the Atlantic Sunrise Project,[40] and the expected upgrade of an existing Columbia Gas Transmission (Columbia) pipeline,[41] the capacity of the Virginia-Carolinas region's natural gas infrastructure is more than sufficient to meet expected future peak demand.[42] Commenters also note that both Duke Energy Progress and Duke Energy Carolinas have testified before their state commission that adequate pipeline capacity already exists for their planned construction projects.[43]

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[39] Synapse Energy Economics Inc., *Are the Atlantic Coast Pipeline and Mountain Valley Pipeline Necessary?* (Sept. 12, 2016) (filed Dec. 20, 2016) (Synapse Study).

[40] The Atlantic Sunrise Project, approved by the Commission on February 3, 2017, will provide up to an additional 1.7 million Dth/d of firm transportation service from northern Pennsylvania to Alabama. *Transcontinental Gas Pipe Line Company, LLC*, 158 FERC ¶ 61,125 (2017) (*Transco*).

[41] The Synapse Study cites the WB Express Project, which would provide up to an additional 1.3 million Dth/d of bi-directional firm transportation service on Columbia's system, which is located in the ACP Project area. The WB Express Project is currently pending before the Commission, in Docket No. CP16-38-000.

[42] Specifically, the Synapse Study analyzes the winter peak hour gas usage under various scenarios, and finds that, even under the highest gas usage scenario modeled, natural gas supply exceeds demand by approximately 100 MMcf through 2030. Synapse Study at Figure ES-2.

[43] *See, e.g.,* Friends of Nelson July 5, 2017 Comments at 29 (citing Direct Testimony of Swati V. Daji, NCUC Docket No. E-100-147, at 14 (Feb. 16, 2017) ("Currently, Duke Energy has agreements in place that provide firm transportation to eleven current and future gas generation facilities in North and South Carolina including all of Duke Energy's current and approved combined cycle facilities as well as several combustion turbine sites")).

31. Commenters also state that the U.S. Department of Energy (DOE) found that average pipeline utilization between 1998 and 2013 is only 54 percent and that with changes to existing infrastructure, new natural gas pipelines will not likely be needed to supply gas to Southeastern markets.[44] Additionally, commenters note that the Commission has repeatedly found that if pipeline projects are not built, production would reach markets by alternative means.

32. Moreover, commenters assert that relying on Transco's and Columbia's systems has the added benefit of providing shippers more diverse supply sources. Commenters state that the lower cost of gas from the Appalachian Basin is offset by Atlantic's high transportation costs. Thus, commenters conclude that supplying gas by reconfiguring existing infrastructure through pipeline reversals or expansions of existing systems would be more economical and have less of an impact on the environment.

ii. <u>Insufficient Demand for Natural Gas in Virginia and North Carolina</u>

33. Commenters also contend that there is a lack of need for additional natural gas in the markets being served by the ACP Project. Commenters assert that neither Virginia nor North Carolina is expected to experience an increase in natural gas demand, calling into question whether additional natural gas-fired generation will be built.[45]

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[44] *See, e.g.,* Shenandoah Valley Network October 23, 2015 Motion to Intervene at 12 (citing U.S. DEP'T OF ENERGY, *NATURAL GAS INFRASTRUCTURE IMPLICATIONS OF INCREASED DEMAND FROM THE ELECTRIC POWER SECTOR*, (Feb. 2015), http://energy.gov/epsa/ downloads/report-natural-gas-infrastructure-implications-increased-demand-electricpower-sector).

[45] Commenters cite: (1) the utilities downward revisions to their load forecasts; (2) the U.S. Energy Information Administration's (EIA) 2017 Energy Outlook, which estimates that South Atlantic demand for natural gas for electricity generation will decrease from 2015 to 2020; and (3) a study by ICF International, which found that Virginia is not likely to experience a significant increase in natural gas demand. *See, e.g.,* Shenandoah Valley Network June 21, 2017 Motion for Evidentiary Hearing (citing Direct Testimony of James F. Wilson, Va. State Corp. Comm., Case No. PUE-2016-00049 (Aug. 17, 2016); U.S. Energy Information Admin., Annual Energy Outlook 2017 Reference Case Table A2, (Jan. 2017), https://www.eia.gov/outlooks/aeo/; ICF International, *The Economic Impacts of the Atlantic Coast Pipeline* (February 9, 2015)).

34. Commenters further contend that the Integrated Resource Plans of Dominion Virginia Power,[46] Duke Energy Progress, and Duke Energy Carolinas overestimate future demand.[47] Specifically, commenters state that Duke Energy Progress' and Duke Energy Carolinas' 2016 plans may overestimate demand because they (1) assume a peak winter load for the first time; (2) underestimate the growth of renewable generation; and (3) include high reserve margins.[48] With respect to Dominion Virginia Power, commenters note that for 2027, PJM Interconnection's (PJM)[49] 2017 forecast is approximately 3,500 Megawatts (MW) less than Dominion Virginia Power's own projection from its 2016 plan.[50]

35. The 2016 Synapse Study, submitted by several commenters, finds that the EIA projections relied upon by Atlantic to show a need for additional capacity in the region are out of date and have been significantly modified.[51] Commenters further contend that Atlantic wrongly relies on the Clean Power Plan to support claims of natural gas demand

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[46] Dominion Virginia Power will receive gas from the ACP Project from Virginia Power Services Energy Corp., Inc.

[47] Moreover, commenters note that Duke Energy Carolinas' and Duke Energy Progress' most recent integrated resource plans do not mention the ACP Project as a source of natural gas supply. *See, e.g.,* Friends of Nelson July 5, 2017 Comments at 29 (citing Duke Energy Progress, Integrated Resource Plan (Annual Report) at 16, NCUC Docket E-100-141 (Sept. 1, 2014); Duke Energy Carolinas, Integrated Resource Plan (Annual Report) at 16, NCUC Docket E-100-141 (Sept. 1, 2014)).

[48] *See, e.g.,* Public Interest Groups April 5, 2017 Comments at 23.

[49] PJM is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

[50] *See, e.g.,* Shenandoah Valley Network June 21, 2017 Motion for Evidentiary Hearing (citing Direct Testimony of James F. Wilson, Va. State Corp. Comm., Case No. PUE-2016-00049 at 15-17 (Aug. 17, 2016)).

[51] Synapse Study at 14-15. Commenters further note that EIA, PJM, and the individual utilities have all revised their projections downward from their 2014 assessments, when the ACP Project was initially conceived. *See, e.g.,* Shenandoah Valley Network June 21, 2017 Motion for Evidentiary Hearing at 5.

growth because the Clean Power Plan has been stayed and the current administration is not likely to pursue its implementation.[52]

36. Next, commenters assert that the ACP Project is not needed to supply gas to the Greensville and Brunswick Power Stations, two power plants directly connected to the ACP Project, because those plants are already being served from the same supply region by Transco at a lower rate.[53] Commenters further state that when the power plants were approved by the Virginia State Corporation Commission, Virginia Electric and Power Company cited existing pipelines as its source for natural gas and did not rely on the fact that either plant was connected to the ACP Project.[54] Additionally, commenters note that supplying these same two power plants has already been cited for the approval of two Transco expansion projects.[55] With respect to the potential to supply future generating facilities, commenters note that the location and timing of those generating facilities is not currently known.[56]

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[52] On October 10, 2017, the U.S. Environmental Protection Agency issued a notice of proposed rulemaking to repeal the regulations implementing the Clean Power Plan.

[53] Comparing the recourse rates for the ACP Project to the Transco Southside Expansion Project, which supplies gas to the Brunswick Power Station, commenters state that transporting gas via the ACP Project results in an additional $218.5 million in costs for the first year. *See, e.g.*, Friends of the Central Shenandoah April 3, 2017 Comments at 14.

[54] *See, e.g.*, Shenandoah Valley Network June 21, 2017 Motion for Evidentiary Hearing at 23 (citing State Corporation Commission of Virginia, "Final Order," Case No. PUE-2012-00128 (Aug. 2, 2013) and Application of Virginia Electric and Power Company for Approval and Certification of the Proposed Greensville County Power Station Electric Generation and Related Transmission Facilities Under §§ 56-580 D, 56-265.2 and 56-46.1 of the Code of Virginia and for Approval of a Rate Adjustment Clause, Designated Rider GV, Under § 56-585.1 A 6 of the Code of Virginia, Case No. PUE-2015-00075, at 7).

[55] Transco's Southside Expansion Project, which was approved by the Commission and went into service in 2015, connects to the Brunswick Power Station. The Greensville Power Station will be served by Transco's Southside Expansion Project II, which was approved by the Commission in 2016.

[56] *See, e.g.*, Friends of Nelson April 5, 2017 Comments (citing Atlantic's December 8, 2016 Data Response at Question 3). Commenters state that although the ACP Project is expected to be online by 2019, Duke Energy Carolinas and Duke Energy Progress do not plan to bring new generation online before 2022. With respect to

37. Last, commenters argue that since additional natural gas is not needed to serve market demand in Virginia and North Carolina, the real purpose of the project is to deliver gas to DETI's Cove Point LNG terminal. Commenters contend that the Commission should not grant a certificate for the ACP Project if its primary purpose will be to export natural gas.

iii. Insufficient Natural Gas Production in the Appalachian Basin

38. Commenters argue that there is not sufficient production from the Appalachian Basin to justify the ACP Project and other proposed projects in the region.[57] Commenters assert that shale production will peak around 2020 and then decline significantly, absent a change in natural gas prices. Commenters contend that the EIA projections ignore that shale wells decline quickly (75 to 85 percent in first 3 years) and that the most productive areas of shale plays have already been developed. Thus, they say, it is not realistic to presume that there will be enough supply for the useful life of the ACP and other projects, and that doing so may lead to stranded pipeline and generation assets.

39. Commenters note that industry experts and executives have stated that production in the Appalachian Basin is slowing and takeaway capacity is expected to be overbuilt.[58] Commenters argue that because the price of natural gas has fallen, many shale gas producers may be unable to produce gas at a profitable price and will subsequently shut down their production.

Dominion Virginia Power, commenters note that it has not applied for or obtained approval to construct any new natural gas-fired facilities, much less any plant that will rely exclusively on the ACP Project for fuel supply. *See, e.g.,* Shenandoah Valley Network June 21, 2017 Motion for Evidentiary Hearing.

[57] Commenters cite FERC Office of Enforcement Division of Energy Market Oversight, 2014 State of the Markets Presentation at Slide 8 (March 19, 2015); Joanna Wu, *US Gas Insight*: *Midstream Madness*, Bloomberg New Energy Finance (Mar. 8, 2016); Jeremiah Shelor, *Marcellus/Utica On Pace for Pipeline Overbuild, Says Braziel*, NGI's Daily Gas Price Index (June, 8 2016). *See, e.g.,* Friends of the Central Shenandoah April 3, 2017 Comments at 22-24.

[58] *See, e.g.* Appalachian Mountain Advocates June 2, 2016 Comments at Attachment (Institute for Energy Economics and Financial Analysis, *Risks Associated with Natural Gas Pipeline Expansion in Appalachia* at 11-13 (April 2016) (IEEFA Study)).

iv. Use of Renewable Energy to Serve Electricity Demand

40. Commenters argue that under the NGA, the Commission should reject proposals when alternative proposals would better serve public convenience and necessity, even when the Commission lacks the authority to mandate the alternative.[59] Thus, commenters aver that the Commission should consider whether renewable energy could better serve the need for additional generation in Virginia and North Carolina.[60]

41. Commenters assert that renewable energy may replace the need for the project in the future. Citing the Clean Power Plan and the decreasing costs of renewable energy, commenters note that states will be increasingly moving toward renewable energy to meet emission targets, which may result in stranded natural gas assets. Additionally, commenters note that large energy consumers are increasingly demanding or planning to switch to 100 percent renewable energy to meet their needs. Moreover, Appalachian Mountain Advocates (AMA)[61] assert that unlike renewable energy, which has a fixed fuel cost, natural gas-fired generation poses risks to consumers if natural gas prices fluctuate.

42. Commenters also argue that approval of natural gas infrastructure will foreclose investment in renewable energy sources in the future. Commenters argue that instead of investing in natural gas-fired electricity, utilities should invest in renewable resources, which more closely align with long-term goals to reduce greenhouse gases. Oil Change International argues that any assessment of need for a proposed project should consider climate goals.

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[59] Commenters cite *City of Pittsburgh v. FPC*, 237 F.2d 741, at 756 n.28 (D.C. Cir. 1956).

[60] Commenters state that the Commission must also consider colocation with other pipelines and utility rights-of-way and whether modifications to existing infrastructure can serve the same markets with fewer environmental impacts. The final EIS evaluated these alternatives. *See* Final EIS at § 3.0.

[61] AMA filed comments on behalf of Allegheny Defense Project, Appalachian Voices, Center for Biological Diversity, Chesapeake Climate Action Network, Christians for the Mountains, Citizens Climate Lobby, Dominion Pipeline Monitoring Coalition, Eight Rivers Council, Friends of Water, Mountain Lakes Preservation Alliance, Ohio Valley Environmental Coalition, Sierra Club, Virginia Chapter of the Sierra Club, West Virginia Highlands Conservancy, and Wild Virginia.

v. **Regional Plan for Natural Gas Pipeline Infrastructure**

43. Commenters contend that the Commission should evaluate the need for new pipeline infrastructure on a region-wide basis. As noted above, commenters argue that there is insufficient supply in the Appalachian Basin for all of the proposed pipeline projects and there is insufficient need for new pipeline capacity serving markets in Virginia and North Carolina. Commenters argue that if all the projects serving the Appalachian Basin are built, ratepayers will be paying for unused capacity.[62] AMA argues that the Commission must conduct an independent investigation of the actual need for the ACP Project in order to protect consumers, as required by the NGA. Commenters further assert that even if more pipeline capacity is needed to serve southern markets, other pipeline projects may be more environmentally advantageous.[63]

vi. **Precedent Agreements with Affiliated Shippers**

44. Commenters argue that because all but one of the shippers on the ACP Project are affiliated with the project's developers, those contracts are not sufficient to demonstrate project need. Commenters argue that the Certificate Policy Statement requires the Commission to examine "all relevant factors reflecting on the need for the project"[64] and states that "traditional factors for establishing the need for a project, such as contracts and precedent agreements, may no longer be a sufficient indicator that a project is in the public convenience and necessity."[65] Additionally, commenters emphasize that the

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[62] *See, e.g.*, Public Interest Groups April 5, 2017 Comments (citing IEEFA Study at 12).

[63] The Synapse Study avers that considering each new pipeline proposal in isolation ignores important alternatives, such as upgrades to existing pipelines and storage facilities, which would increase regional natural gas supply capacity and avoid the adverse impacts on communities or the environment. Synapse Study at 4. Similarly, the IEEFA Study argues that the Commission should evaluate regional requirements for additional pipeline capacity similar to other infrastructure programs such as electric transmission and highways. IEEFA Study at 6.

[64] *See, e.g.*, Friends of Nelson April 5, 2017 Comments (citing Certificate Policy Statement, 88 FERC at 61,747).

[65] *See, e.g.*, Friends of Nelson April 5, 2017 Comments (citing Certificate Policy Statement, 90 FERC at 61,390). Commenters also cite to former Chairman Norman Bay's statement that the Commission should look beyond precedent agreements and reevaluate its test for need. *See, e.g.*, Friends of Nelson April 5, 2017 Comments (citing

Certificate Policy Statement states that "[a] project that has precedent agreements with multiple new customers may present a greater indication of need than a project with only a precedent agreement with an affiliate"[66] and "using contracts as the primary indicator of market support for the proposed pipeline project . . . raises additional issues when the contracts are held by pipeline affiliates."[67] Friends of the Central Shenandoah note that in Order No. 497, the Commission stated that there is an economic incentive for the pipeline to favor "transactions conducted on a pipeline that benefits the pipeline or the corporate group of which it is a part."[68]

45. Commenters further contend that Atlantic's failure to provide a study showing that the ACP Project is needed conflicts with the Certificate Policy Statement. Commenters note that the policy statement states that when, as here, a new pipeline will serve markets already reached by existing infrastructure, "the evidence necessary to establish the need for the project will usually include a market study."[69]

46. Next, Commenters argue that, without looking behind the precedent agreements supporting the ACP Project, the Commission cannot determine whether the shipper commitments represent a genuine growth in market demand to warrant construction. Commenters assert that affiliated shippers have no incentive to seek out the lowest cost transportation for their gas. Instead, the shippers are incentivized to contract with their affiliate since all costs, including the rate of return of 14 percent, are recoverable from captive ratepayers.[70] Thus, all the risks associated with the pipeline project are shifted to

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Separate Statement of Chairman Bay in *National Fuel Gas Supply Corp.*, 158 FERC ¶ 61,145 (2017)).

[66] *See, e.g.*, Friends of Nelson April 5, 2017 Comments (citing Certificate Policy Statement, 88 FERC at 61,748).

[67] *See, e.g.*, Friends of Nelson April 5, 2017 Comments (citing Certificate Policy Statement, 88 FERC at 61,744).

[68] Friends of the Central Shenandoah April 3, 2017 Comments at 10 (citing *Inquiry Into Alleged Anticompetitive Practices Related to Marketing Affiliates of Interstate Pipelines*, Order No. 497, FERC Stats. & Regs. ¶ 30,820 (1988), *order on reh'g*, Order No. 497-A, FERC Stats. & Regs. ¶ 30,868 (1989)).

[69] *See, e.g.*, Friends of Nelson April 5, 2017 Comments (citing Certificate Policy Statement, 88 FERC at 61,748).

[70] Commenters claim that Dominion Resources, Inc. and Duke Energy Corporation will likely realize more profits from sales of electricity from gas-fired

captive ratepayers.[71] Moreover, Public Interest Groups urge the Commission to view with skepticism precedent agreements that were not connected to the open season process.[72]

47. Last, AMA avers that the public utility regulators in Virginia and North Carolina have not conducted a meaningful review of the precedent agreements and whether the shippers' should recover the costs of the contracts from ratepayers. AMA asserts that it is unlikely that state regulators will have the opportunity to examine the economic necessity for the pipeline prior to a decision on Atlantic's certificate application.[73] AMA states that even though the North Carolina Utilities Commission authorized Duke Energy Progress, Duke Energy Carolinas, and Piedmont to enter into affiliated contracts with Atlantic in 2014, it did not evaluate the necessity for the pipeline or consider whether the affiliated contracts would allow an unnecessary project to proceed.[74] Moreover, AMA notes that those approvals occurred nearly three years ago, and, according to Duke Energy's own analysis, the market demand for natural gas for electricity generation in North Carolina has since dropped.

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generators because they own the ACP Project, rather than simply purchasing natural gas and counting it as an expense.

[71] However, the IEEFA Study acknowledges that investors are subject to some risk regarding the project if state regulators refuse to let the affiliated shippers pass through the costs of the transportation contracts to ratepayers. IEEFA Study at 21.

[72] Public Interest Groups April 5, 2017 Comments at 28 (citing *Millennium Pipeline Co., L.P.*, 100 FERC ¶ 61,277, at 62,141 (2002) (citing *Independence Pipeline Co.*, 89 FERC ¶ 61,283, at 61,840 (1999)) ("The proffered precedent agreement was not the result of, or related to, Independence's open season. For this reason, we found that the DirectLink agreement did not constitute reliable evidence of market need to support a finding that the proposal was required by the public convenience and necessity.")).

[73] Similarly, the IEEFA Study, which was submitted by multiple commenters, concludes that the state regulatory processes do not have the ability to prevent overbuilding because any prudency determination by a state regulator would likely occur after the pipeline is already placed into service and any challenge to the rates charged by the interstate pipeline would be under the Commission's exclusive jurisdiction.

[74] AMA notes that Dominion Virginia Power has not sought approval from the Virginia State Corporation Commission for its affiliate contracts to accept gas from the pipeline, and the Virginia State Corporation Commission will not review contracts for gas purchases on the ACP Project until after pipeline construction concludes.

vii. Inadequacy of Atlantic's Studies

48. Several commenters filed a 2015 review, conducted by Synapse, of the ICF International analysis and the Chmura Economics and Analytics analysis filed by Atlantic with its application.[75] The 2015 Synapse Report concluded that the analyses overestimated the benefits of the pipeline.[76] Specifically, the 2015 Synapse Report finds that the ICF International analysis wrongly assumes, without support, that the price differential between the Dominion South point and Henry Hub will be between $1.50 and $1.75. The 2015 Synapse Report notes that in 2015, on average, the price spread was only $0.81[77] and that the prices at the Dominion South point and Henry Hub are converging.[78] Moreover, the 2015 Synapse Report finds that even assuming the price differential reported by ICF International, because of higher transportation costs associated with the project, there are no annual net savings from the ACP Project until 2027.[79]

49. Next, the 2015 Synapse Report states that it is unclear whether ICF International's energy cost savings for Virginia residents is properly calculated. The 2015 Synapse Report notes that due to the state's membership in PJM, any cost savings would be distributed throughout the entire region and not be solely allocated to Virginia customers.[80] The 2015 Synapse Report also states that the ICF International analysis wrongly asserts that the proposed project will help consumers by reducing volatility in the market because volatility in the wholesale markets do not create volatility in the regulated retail markets.[81] Last, the 2015 Synapse Report asserts that ICF International

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[75] Synapse Energy Economics Inc., *Atlantic Coast Pipeline Benefits Review* (June 12, 2015) (filed June 12, 2016) (2015 Synapse Report).

[76] The ICF International analysis, the Chmura Economics and Analytics analysis, and 2015 Synapse Study discuss the effects of the ACP Project on jobs and the economy of the region. These socioeconomic effects are discussed in the final EIS and below. Here, we review only those issues related to the need for the proposed project.

[77] Commenters also note that as more takeaway capacity from the Marcellus shale is built, the price differential will decrease even more.

[78] 2015 Synapse Report at 2-3.

[79] *Id.* at 4. The IEEFA Study comes to similar conclusions when analyzing Atlantic's claims. IEEFA Study at 19.

[80] 2015 Synapse Report at 6-7.

[81] *Id.* at 7.

wrongly states that the proposed project will enhance electric reliability in the region. The 2015 Synapse Report asserts that any improvement in electric reliability would be the result of new generation being built and not because of the pipeline being in place.[82]

viii. Atlantic's Answer

50. In its December 4, 2015 answer, Atlantic states that it has entered into precedent agreements with end users for 96 percent of its capacity. Atlantic notes that the genesis for the project was a response to a solicitation by Duke Energy Corporation and Piedmont for competitive firm transportation to North Carolina to serve its growing need for natural gas. Additionally, Virginia Power Services Energy Corporation also requested proposals for firm transportation to serve natural gas-fired generation in Virginia. Atlantic states that these customers viewed the ACP Project as the best way to support their growing need for natural gas. Atlantic notes that all the project's customers and several producer groups have filed comments supporting the project.

51. Atlantic contends that the Commission's long-standing policy is that contracts are strong evidence of market demand and commenters wrongly assert that market studies are the best evidence of demand for a project. Atlantic further notes that EIA studies document growing demand for natural gas in Virginia and North Carolina and that the Clean Power Plan encourages utilities to switch from coal-fired generation to natural gas. Moreover, Atlantic asserts that the ACP Project will improve electric reliability by enhancing gas supply security and providing flexibility and optionality to generators. Atlantic contends that the ACP Project will result in a net energy cost savings to consumers of $377 million between 2019 and 2038.

52. Next, Atlantic asserts that existing and proposed pipelines cannot replace the need for the ACP Project. Atlantic states that its customers chose the ACP Project as the best means to meet their needs and the Commission has no basis to second guess those commercial decisions. With respect to unused capacity on existing pipelines, Atlantic notes that the historic load factor does not suggest that firm transportation is available to Atlantic's customers. Atlantic acknowledges that flow reversals of existing pipelines are occurring, but states that those projects have their own customers.

53. With respect to renewable energy, Atlantic states that natural gas-fired generation provides flexibility for the region's utilities to continue working to incorporate renewable energy into their portfolios. Atlantic notes that its customers have determined that more natural gas generation is required and the ACP Project is the best way to serve those generators.

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[82] *Id.*

ix. Commission Determination

54. The Certificate Policy Statement established a new policy under which the Commission would allow an applicant to rely on a variety of relevant factors to demonstrate need, rather than continuing to require that a percentage of the proposed capacity be subscribed under long-term precedent or service agreements.[83] These factors might include, but are not limited to, precedent agreements, demand projections, potential cost savings to consumers, or a comparison of projected demand with the amount of capacity currently serving the market.[84] The Commission stated that it would consider all such evidence submitted by the applicant regarding project need. Nonetheless, the policy statement made clear that, although precedent agreements are no longer required to be submitted, they are still significant evidence of project need or demand.[85] As the court affirmed in *Minisink Residents for Environmental Preservation & Safety v. FERC*, the Commission may reasonably accept the market need reflected by the applicant's existing contracts with shippers.[86] Moreover, it is current Commission policy to not look behind precedent or service agreements to make judgments about the needs of individual shippers.[87]

55. We find that Atlantic has sufficiently demonstrated that there is market demand for the project. Atlantic has entered into long-term, firm precedent agreements with six shippers for 1,440,000 Dth/d of firm transportation service, approximately 96 percent

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[83] Certificate Policy Statement, 88 FERC at 61,747. Prior to the Certificate Policy Statement, the Commission required a new pipeline project to have contractual commitments for at least 25 percent of the proposed project's capacity. *See* Certificate Policy Statement, 88 FERC ¶ 61,227 at 61,743. The ACP Project, at 96 percent subscribed, would have satisfied this prior, more stringent, requirement.

[84] Certificate Policy Statement, 88 FERC at 61,747.

[85] *Id.*

[86] *Minisink Residents for Envtl. Pres. & Safety v. FERC*, 762 F.3d 97, 110 n.10 (D.C. Cir. 2014); *see also Sierra Club v. FERC,* 867 F.3d 1357, 1379 (D.C. Cir. 2017) (finding that pipeline project proponent satisfied the Commission's "market need" where 93 percent of the pipeline project's capacity has already been contracted for).

[87] Certificate Policy Statement, 88 FERC at 61,744 (citing *Transcontinental Gas Pipe Line Corp.*, 82 FERC ¶ 61,084, at 61,316 (1998)).

of the system's capacity.[88] Further, Ordering Paragraph (K) of this order requires that Atlantic and DETI file a written statement affirming that they have executed final contracts for service at the levels provided for in their precedent agreements prior to commencing construction. The shippers on the ACP Project supply gas to end users and electric generators, and those shippers have determined that natural gas will be needed and the ACP Project is the preferred means of obtaining that gas. We find that the contracts entered into by those shippers are the best evidence that additional gas will be needed in the markets that the ACP Project intends to serve. We also find that end users will generally benefit from the project because it would develop gas infrastructure that will serve to ensure future domestic energy supplies and enhance the pipeline grid by connecting sources of natural gas to markets in Virginia and North Carolina.[89]

56. We disagree with commenters' assertion that the Commission should examine the need for pipeline infrastructure on a region-wide basis. Commission policy is to examine the merits of individual projects and each project must demonstrate a specific need.[90] While the Certificate Policy Statement permits the applicant to show need in a variety ways, it does not suggest that the Commission should examine a group of projects together and pick which projects best serve an estimated future regional demand. In fact, projections regarding future demand often change and are influenced by a variety of factors, including economic growth, the cost of natural gas, environmental regulations, and legislative and regulatory decisions by the federal government and individual states. Given the uncertainty associated with long-term demand projections, such as those presented in the Synapse Study and other studies cited by commenters, where an applicant has precedent agreements for long-term firm service, the Commission deems the precedent agreements to be the better evidence of demand. Thus, the Commission evaluates individual projects based on the evidence of need presented in each proceeding. Where, as here, it is demonstrated that specific shippers have entered into precedent

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[88] *Constitution Pipeline Company, LLC*, 154 FERC ¶ 61,046, at P 21 (2016) ("Although the Certificate Policy Statement broadened the types of evidence certificate applicants may present to show the public benefits of a project, it did not compel an additional showing … [and] [n]o market study or other additional evidence is necessary where … market need is demonstrated by contracts for 100 percent of the project's capacity.").

[89] *See ETC Tiger Pipeline, LLC*, 131 FERC ¶ 61,010, at P 20 (2010).

[90] With respect to comments requesting the Commission to assess the market demand for gas to be transported by other proposed interstate pipeline projects, we note that the Commission will evaluate the proposals in those proceedings in accordance with the criteria established in our Certificate Policy Statement.

agreements for project service, the Commission places substantial reliance on those agreements to find that the project is needed.

57. With respect to the use of existing infrastructure or new renewable generation to meet the project's need, our environmental review considered the potential for energy conservation and renewable energy sources, and the availability of capacity on other pipelines, to serve as alternatives to the ACP Project and concluded that they do not presently serve as practical alternatives to the project.[91] Thus, contrary to commenters' assertions, we are not persuaded that authorization of the ACP Project would lead to the overbuilding of pipeline infrastructure.

58. In addition, we are not persuaded by commenters' contention that there is insufficient supply in the Appalachian Basin to support the pipeline. While we agree, and Atlantic acknowledges, the intended source of supply for the ACP Project will be production in the Appalachian Basin, the ACP Project is also connected to other interstate pipelines, such as DETI[92] and Transco, which could potentially supply gas to the project from other areas of supply. Additionally, because, as the commenters note, the amount of gas that will be produced from the region is reflective of, among other things, the price of natural gas, projections regarding the amount of gas available for the ACP Project are speculative.

59. Moreover, the fact that five of the six shippers on the ACP Project are affiliated with the project's sponsors does not require the Commission to look behind the precedent agreements to evaluate project need.[93] When considering applications for new certificates, the Commission's primary concern regarding affiliates of the pipeline as shippers is whether there may have been undue discrimination against a non-affiliate

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[91] *See* Final EIS at 5-38 (concluding that existing pipelines do not have the capacity to transport the required volumes of gas and that generation of electricity from renewable energy sources or the gains realized from increased energy efficiency and conservation are not transportation alternatives and cannot function as a substitute for the proposed projects).

[92] DETI's Supply Header Project would receive natural gas from two interstate pipelines, Rockies Express Pipeline, LLC and Texas Eastern Transmission, and from regional production at two receipt points. Atlantic's September 18, 2015 Application at Exhibit I.

[93] *Millennium Pipeline Co., L.P.*, 100 FERC ¶ 61,277 at P 57 ("as long as the precedent agreements are long-term and binding, we do not distinguish between pipelines' precedent agreements with affiliates or independent marketers in establishing the market need for a proposed project").

shipper.[94] Here, no such allegations have been made, nor have we found that the project sponsors have engaged in any anticompetitive behavior. As discussed above, Atlantic held both a non-binding and binding open season for capacity on the project and all potential shippers had the opportunity to contract for service. Moreover, Atlantic's tariff, as discussed below, ensures that any future shipper will not be unduly discriminated against.

60. We also do not find merit in the commenters' argument that the proposed project will be subsidized by the affiliated shippers' captive ratepayers. First, to the extent a ratepayer receives a beneficial service, paying for that service does not constitute a "subsidy."[95] Further, as several commenters and the Institute for Energy Economics and Financial Analysis, *Risks Associated with Natural Gas Pipeline Expansion in Appalachia* study (IEEFA study) note, state utility regulators must approve any expenditures by state-regulated utilities. We disagree with commenters who suggest that once the Commission has made a determination in this proceeding, state regulators cannot effectively review the expenditures of utilities that they regulate. In fact, any attempt by the Commission to look behind the precedent agreements in this proceeding might infringe upon the role of state regulators in determining the prudency of expenditures by the utilities that they regulate. Here, the North Carolina Utilities Commission has already approved the precedent agreements between Atlantic and Duke Energy Progress, Duke Energy Carolinas, and Piedmont. With respect to the precedent agreement to supply natural gas to Virginia Electric and Power Company, issues related to the utility's ability to recover costs associated with its decision to subscribe for service on the ACP Project involve matters to be determined by the Virginia State Corporation Commission; those concerns are beyond the scope of the Commission's jurisdiction. Should they elect to construct the projects before affirmative action by the state regulators, the applicants will be at risk of not being able to recover some, or any, of their costs.

61. Further, we disagree with commenters claim that because Greensville and Brunswick Power Stations are already served by Transco's pipeline, the ACP Project is not needed. The fact that these two generating facilities are already connected to interstate pipelines does not diminish the reliability benefits of having alternative sources of natural gas for those generators in case of a supply disruption. In addition, the ACP Project will be able supply additional existing generation units through interconnections

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[94] *See* 18 C.F.R. § 284.7(b) (2017) (requiring transportation service to be provided on a non-discriminatory basis).

[95] *See* Certificate Policy Statement, 90 FERC ¶ at 61,393.

with existing pipelines. For example, Atlantic cited 14 Dominion Virginia Power and 5 Duke Energy Progress facilities that could be served by the ACP Project.[96]

62. Lastly, allegations that the project is not needed because gas may be exported are not persuasive. The Commission does not have jurisdiction to authorize the exportation or importation of natural gas. Such jurisdiction resides with the DOE, which must act on any applications for natural gas export or import authority.[97] Moreover, the ACP Project's shippers are domestic end users of natural gas and there is no evidence in the record that these end users intend to use their capacity to provide gas to an export terminal.

63. In conclusion, we find that the ACP Project will provide reliable natural gas service to end use customers. Precedent agreements signed by Atlantic for approximately 96 percent of the project's capacity adequately demonstrate that the project is needed.

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[96] Atlantic's December 8, 2016 Data Response at Question 3.

[97] Section 3(a) of the NGA provides, in part, that "no person shall export any natural gas from the United States to a foreign country or import any natural gas from a foreign country without first having secured an order of the Commission authorizing it to do so." 15 U.S.C. § 717b(a) (2012). In 1977, the Department of Energy Organization Act transferred the regulatory functions of section 3 of the NGA to the Secretary of Energy. 42 U.S.C. § 7151(b) (2012). Subsequently, the Secretary of Energy delegated to the Commission authority to "[a]pprove or disapprove the construction and operation of particular facilities, the site at which such facilities shall be located, and with respect to natural gas that involves the construction of new domestic facilities, the place of entry for imports or exit for exports." DOE Delegation Order No. 00-004.00A (effective May 16, 2006). The proposed facilities are not located at a potential site of exit for natural gas exports. Moreover, the Secretary of Energy has not delegated to the Commission any authority to approve or disapprove the import or export of the commodity itself, or to consider whether the exportation or importation of natural gas is consistent with the public interest. *See Corpus Christi Liquefaction, LLC*, 149 FERC ¶ 61,283, at P 20 (2014) (*Corpus Christi*). *See also National Steel Corp.*, 45 FERC ¶ 61,100, at 61,332-33 (1988) (observing that DOE, "pursuant to its exclusive jurisdiction, has approved the importation with respect to every aspect of it except the point of importation" and that the "Commission's authority in this matter is limited to consideration of the place of importation, which necessarily includes the technical and environmental aspects of any related facilities").

c. Existing Pipelines and their Customers

64. The ACP Project is designed to transport domestically sourced gas from Appalachian Basin supply areas to markets in West Virginia, Virginia, and North Carolina. Commenters assert that the project will negatively impact existing pipelines because any natural gas transported by the ACP Project would not be available for transport on an existing pipeline. As stated above, the EIS analyzed the availability of capacity on other pipelines to serve as alternatives to the ACP Project, and concluded that they do not presently serve as practical alternatives to the project.[98] Further, no transportation service provider or captive customer in the same market has protested this project. Therefore, we find that the ACP Project will have no adverse impact on existing pipelines or their captive customers.

d. Landowners and Communities

65. Regarding impacts on landowners and communities along the project route, Atlantic proposes to locate its pipeline within or parallel to existing utility corridors where feasible. Approximately nine percent of Atlantic's pipeline rights-of-way will be collocated or adjacent to existing pipeline, roadway, railway, or utility rights of way.[99] Atlantic also proposes to use available capacity on the Piedmont system to avoid duplicative pipeline construction on undisturbed lands. Atlantic participated in the Commission's pre-filing process and has been working to address landowner and community concerns and input. Specifically, Atlantic incorporated 201 route variations, totaling 199 miles, into its proposed route for various reasons, including landowner requests, avoidance of sensitive resources, or engineering considerations.[100] Additionally, Atlantic has stated that it will make good faith efforts to negotiate with landowners for any needed rights, and will resort only when necessary to the use of the eminent domain. Accordingly, while we are mindful that Atlantic has been unable to reach easement agreements with many landowners, for purposes of our consideration under the Certificate Policy Statement, we find that Atlantic has generally taken sufficient steps to minimize adverse impacts on landowners and surrounding communities.

66. A number of commenters request that the Commission not grant Atlantic eminent domain authority. The Commission itself, however, does not confer eminent domain powers. Under NGA section 7, the Commission has jurisdiction to determine if the

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[98] Final EIS at 5-38.

[99] *Id.* at 2-20.

[100] *Id.* at 3-51.

construction and operation of proposed interstate pipeline facilities are in the public convenience and necessity. Once the Commission makes that determination, it is NGA section 7(h) that authorizes a certificate holder to acquire the necessary land or property to construct the approved facilities by exercising the right of eminent domain if it cannot acquire the easement by an agreement with the landowner.[101]

67. Next, commenters state that the Certificate Policy Statement creates a balancing test whereby the Commission balances the need for the project against the impact on landowners. Commenters contend that in this case, the balancing test requires denial of the ACP Project because of Atlantic's lack of colocation with existing rights-of-way, its extensive use of private land,[102] and its negative effects on property values and economic activity.

68. The Certificate Policy Statement "allows the Commission to take into account the different interests that must be considered."[103] In this vein, the policy statement specifically noted that where a pipeline has acquired property rights for a proposed project, the benefits needed to be shown would be less than in a case where no land rights had been previously acquired by negotiation.[104] Thus, the Certificate Policy Statement specifically contemplated a scenario where, if a company might not be able to acquire a perhaps significant amount of property rights through negotiation, the Commission might deny the application if there has not been a sufficient demonstration of need.[105] However, here, as discussed above, Atlantic has demonstrated public benefits for the proposed project. Approximately 96 percent of the ACP Project is subscribed under long-term firm transportation precedent agreements, a strong showing of need.[106]

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[101] 15 U.S.C. § 717f(h) (2012).

[102] Commenters note that the amount of land that will be acquired through eminent domain is not publically available, but suggest that it is significant.

[103] Certificate Policy Statement, 88 FERC at 61,749.

[104] *Id.*

[105] *See Jordan Cove Energy Project, L.P.*, 154 FERC ¶ 61,190 (2016), *reh'g denied*, 157 FERC ¶ 61,194; *Turtle Bayou Gas Storage Company, LLC*, 135 FERC ¶ 61,233 (2011).

[106] Certificate Policy Statement, 88 FERC at 61,749 ("if an applicant had precedent agreements with multiple parties for most of the new capacity, that would be strong evidence of market demand and potential public benefits").

69. With respect to the lack of colocation with existing rights-of-way, the final EIS evaluated numerous alternatives where the pipeline would be collocated with existing rights-of-way and found that many of those alternatives did not offer significant environmental advantages or were technically infeasible when compared to Atlantic's proposed route. As a result of input from Commission staff and stakeholders during the pre-filing process, Atlantic revised its route to parallel various existing infrastructure corridors and thus added nearly 60 miles of colocation to the project. Therefore, we find that Atlantic has made a reasonable effort to collocate its pipeline with existing rights-of-way.

e. Conclusion

70. We find that the benefits that the ACP Project will provide to the market outweigh any adverse economic effects on existing shippers, other pipelines and their captive customers, and on landowners and surrounding communities. Consistent with the criteria discussed in the Certificate Policy Statement and subject to the environmental discussion below, we find that the public convenience and necessity requires approval of Atlantic's proposal, as conditioned in this order.

2. DETI Supply Header Project

71. As stated, the threshold requirement for pipelines proposing new projects is that the applicant must be prepared to financially support the project without relying on subsidization from its existing customers. The Commission has determined, in general, that where a pipeline proposes to charge incremental rates for new construction that are higher than the company's existing system rates, the pipeline satisfies the threshold requirement that the project will not be subsidized by existing shippers.[107] Here, DETI proposes an incremental firm transportation base reservation rate, which is higher than its existing system-wide rate, to recover the costs of the project. The proposed incremental rates are calculated to recover all construction, installation, operation, and maintenance costs associated with the project. Accordingly, we find that the Supply Header Project will not be subsidized by existing customers and satisfies the threshold no-subsidy requirement under the Certificate Policy Statement.

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[107] *See Transcontinental Gas Pipe Line Corp.*, 98 FERC ¶ 61,155, at 61,552 (2002) (noting that the Commission has previously determined that where a pipeline proposes to charge an incremental rate for new construction, the pipeline satisfies the threshold requirement that the project will not be subsidized by existing shippers) (citations omitted); *see also, Dominion Transmission, Inc.*, 155 FERC ¶ 61,106 (2016) (same).

72. We also find that the proposal will not adversely affect DETI's existing customers because there will be no degradation of existing service. In addition, other pipelines and their captive customers will not be adversely impacted because the proposal is not intended to replace service on other pipelines. Rather, the project would allow DETI to provide additional transportation services to Atlantic on its system. Further, no pipeline or their captive customers have protested the application.

73. Moreover, DETI has designed the Supply Header Project to minimize impacts on landowners and surrounding communities. Approximately 31 percent of the right-of-way for the proposed project will be collocated or adjacent to existing pipeline, roadway, railway, or utility rights of way.[108] Additionally, most of the project facility installations will be on lands that are either owned by DETI or on which DETI holds leaseholder or easement rights.

74. We also find that DETI's proposed abandonment of facilities is permitted by the public convenience and necessity.[109] As stated above, the two compressor units at the Hastings Compressor Station currently serve a gathering function. Therefore, their abandonment would not affect any of DETI's jurisdictional transportation or storage customers. Last, no shipper affected by the proposed abandonment has filed comments in opposition to DETI's proposal.

75. We find that the benefits that the Supply Header Project will provide to the market outweigh any adverse effects on existing shippers, other pipelines and their captive customers, and on landowners and surrounding communities. Consistent with the criteria discussed in the Certificate Policy Statement and subject to the environmental discussion below, we find that the public convenience and necessity requires approval of DETI's proposal, as conditioned in this order.

3. <u>Eminent Domain Authority</u>

76. Bold Alliance, Bold Education Fund, Friends of Nelson, and individual landowners (collectively, Bold Alliance) filed a petition for declaratory order and injunctive relief in Federal District Court for the District of Columbia.[110] Bold Alliance alleges that the eminent domain provisions of the NGA and the Commission's Certificate

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[108] Final EIS at 2-20.

[109] 15 U.S.C. § 717f(b) (2012).

[110] The petition was filed with the Commission on September 6, 2017.

Policy Statement do not further a public use, and therefore, violate the Due Process Clause and Takings Clause of the Fifth Amendment.[111]

77. As stated above, the Commission itself does not confer eminent domain powers. Under NGA section 7, the Commission has jurisdiction to determine if the construction and operation of proposed interstate pipeline facilities are in the public convenience and necessity. Once the Commission makes that determination and issues a natural gas company a certificate of public convenience and necessity, it is NGA section 7(h) that authorizes that certificate holder to acquire the necessary land or property to construct the approved facilities by exercising the right of eminent domain if it cannot acquire the easement by an agreement with the landowner.[112]

78. While this matter is currently before the court, we note that Bold Alliance's legal theory is unfounded. Bold Alliance generally argues that the Commission's certification process falls short of the standard required by the Constitution for a taking: that the exercise of eminent domain is for a "public use." As noted above, Congress provided in NGA section 7(h) that a certificate holder was entitled to use eminent domain. Congress did not suggest that there was a further test, beyond the Commission's determination under NGA section 7(c)(e),[113] that a proposed pipeline was required by the public convenience and necessity, such that certain certificated pipelines furthered a public use, and thus were entitled to use eminent domain, while others did not. The Commission has interpreted the section 7(c)(e) public convenience and necessity determination as requiring the Commission to weigh the public benefit of the proposed project against the project's adverse effects.[114] We undertake this balancing through our application of the

[111] On September 25, 2017, Bold Alliance filed comments raising the same issues discussed in their petition for declaratory order. We reject Bold Alliance's comments as untimely.

[112] 15 U.S.C. § 717f(h) (2012).

[113] 15 U.S.C. § 717f(e).

[114] As the agency that administers the Natural Gas Act, and in particular as the agency with expertise in addressing the public convenience and necessity standard in the Act, the Commission's interpretation and implementation of that standard is accorded deference. *See Chevron, USA, Inc. v. Nat. Res. Def. Council, Inc.*, 467 U.S. 837, 842-43 (1984); *Delaware Riverkeeper Network v. FERC*, 857 F.3d 388, 392 (D.C. Cir. 2017); *Office of Consumers Counsel v. FERC*, 655 F.2d 1132, 1141 (D.C. Cir. 1980); *Total Gas & Power N. Am., Inc. v. FERC*, No. 4:16-1250, 2016 WL 3855865, at *21 (S.D. Tex. July 15, 2016), aff'd, 859 F.3d 325 (5th Cir. 2017); *see also MetroPCS Cal., LLC v. FCC*, 644 F.3d 410, 412 (D.C. Cir. 2011) (under Chevron, the Court "giv[es] effect to

Certificate Policy Statement criteria, under which we balance the public benefits of a project against the residual adverse effects.[115] Thus, through this balancing process we make findings that support our ultimate conclusion that the public interest is served by the construction of the proposed project.[116] Accordingly, once a natural gas company obtains a certificate of public convenience and necessity, it may exercise the right of eminent domain in a U.S. District Court or a state court.

79. The Commission, having determined that the ACP Project is in the public convenience and necessity, need not make a separate finding that the project serves a "public use" to allow the certificate holder to exercise eminent domain. In short, the Commission's public convenience and necessity finding is equivalent to a "public use" determination.[117] In enacting the NGA, Congress clearly articulated that the transportation and sales of natural gas in interstate commerce for ultimate distribution to the public is in the public interest.[118] This congressional recognition that natural gas

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clear statutory text and defer[s] to an agency's reasonable interpretation of any ambiguity").

[115] Certificate Policy Statement, 88 FERC at 61,747-49,

[116] *Midcoast Interstate Transmission, Inc. v. FERC*, 198 F.3d 960, 973 (D.C. Cir. 2000) (because the Commission declared that the subject pipeline would serve the public convenience and necessity, the takings complained of did serve a public purpose); *see also Guardian Pipeline, L.L.C. v. 529.42 Acres of Land*, 210 F. Supp. 2d 971, 974 (N.D. Ill. 2002) (no evidence of public necessity other than the Commission's determination is required).

[117] *See Midcoast Interstate Transm., Inc. v. FERC*, 198 F.3d 960, 973 (D.C. Cir. 2000); *see also*, *e.g.*, *Troy Ltd. v. Renna*, 727 F.2d 287, 301 (3rd Cir. 1984) ("authoriz[ing] an occupation of private property by a common carrier . . . engaged in a classic public utility function" is an "exemplar of a public use"); *E. Tenn. Natural Gas Co. v. Sage*, 361 F.3d 808 (4th Cir. 2004) ("Congress may, as it did in the [Natural Gas Act], grant condemnation power to 'private corporations . . . execut[ing] works in which the public is interested.'") (quoting *Miss. & Rum River Boom Co. v. Patterson*, 98 U.S. 403, 406 (1878)).

[118] 15 U.S.C. § 717(a) (2012) (declaring that the "business of transporting and selling natural gas for ultimate distribution to the public is affected with a public interest"). *See also Thatcher v. Tennessee Gas Transmission Co.*, 180 F.2d 644, 647 (5th Cir. 1950)*(Thatcher)*, *cert. denied*, 340 U.S. 829 (1950) (explaining that Congress, in enacting the NGA, recognized that "vast reserves of natural gas are located in States of our nation distant from other States which have no similar supply, but do have a vital

transportation furthers the public interest is consistent with the Supreme Court's emphasis on legislative declarations of public purpose in upholding the power of eminent domain.[119]

80. Bold Alliance erroneously cites to *Transco*,[120] where the Commission, after evaluating record evidence of need for the project at issue, found that there was a need for the project for purposes of section 7(c) of the NGA[121] and that the project served a public purpose sufficient to satisfy the Takings Clause.[122] We have done the same here. The proposed projects in this proceeding are designed to primarily serve natural gas demand in Virginia and North Carolina. Through the distribution of natural gas from the projects, the public at large will benefit from increased reliability of natural gas supplies. Furthermore, upstream natural gas producers will benefit from the project by being able to access additional markets for their product. Therefore, we conclude that the proposed project is required by the public convenience and necessity.

81. Notwithstanding the fact that we addressed a takings argument raised in *Transco* and here, such a question is beyond our jurisdiction; only the courts can determine whether Congress' action in passing section 7(h) of the NGA conflicts with the Constitution. We note, however, that courts have found eminent domain authority in section 7(h) of the NGA to be constitutional.[123]

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need of the product; and that the only way this natural gas can be feasibly transported from one State to another is by means of a pipe line.").

[119] *Kelo v. City of New London, Conn.*, 545 U.S. 469, 479-80 (2005) (upholding a state statute that authorized the use of eminent domain to promote economic development); *see also id.* at 480 (noting that without exception the Court has defined the concept of "public purpose" broadly, reflecting the Court's longstanding policy of deference to the legislative judgments in this field).

[120] *Transco*, 158 FERC ¶ 61,125.

[121] *Id.* PP 20-33.

[122] *Id.* PP 66-67.

[123] *See Thatcher*, 180 F.2d at 647. In addition, the eminent domain authority in many federal statutes mirror the authority in section 7(h) of the NGA. For instance, section 21 of the Federal Power Act (FPA), 16 U.S.C. § 814 (2012), provides that when a licensee cannot acquire by contract lands or property necessary to construct, maintain, or operate a licensed hydropower project, it may acquire the same by the exercise of the right of eminent domain in a U.S. District Court or a state court. The U.S. Supreme

4. **Antitrust Complaint**

82. On May 12, 2016, Mr. Michael Hirrel filed with the Commission an undated copy of a filing addressed to the Federal Trade Commission (FTC), in which he alleged that Dominion Resources and Duke Energy were in violation of section 2 of the Sherman Act and section 5 of the Federal Trade Commission Act, and asked the FTC to file comments in this proceeding.[124] On June 24, 2016, Mr. Hirrel filed with the Commission a June 23, 2016 letter from the Virginia Chapter of the Sierra Club to the FTC supporting Mr. Hirrel's complaint. On August 30, 2016, DETI and Atlantic filed a response to which Mr. Hirrel responded to on November 4, 2016.

83. Mr. Hirrel's initial filing was made with the FTC, not with the Commission, and accordingly is a matter for the FTC to review. However, Mr. Hirrel is correct when he states in his response[125] that questions regarding competition, including antitrust concerns, may be considered by the Commission in making its public convenience and necessity findings.[126] Here, the Commission has, pursuant to the policy statement, found that the proposed project will not have negative impacts on existing pipelines and their customers, and, to the extent that the filings raised issues concerning the need for the proposed projects and the precedent agreements with affiliated shippers, those issues were discussed above. We see no reason to further address Mr. Hirrel's allegations.

5. **Compressor Station Spacing**

84. Mr. Richard Laska alleges that the ACP Project is overbuilt because the compressor stations on the project are located over 200 miles apart, even though the typical range between compressor stations is 40 to 100 miles. Additionally, Blue Ridge Environmental Defense League questions whether three compressor stations are sufficient for the ACP Project and if other compressor stations are planned, but have not been disclosed. In response to Commission staff's November 23, 2016 data request,

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Court has not questioned the constitutionality of section 21 of the FPA. *See FPC v. Tuscarora Indian Nation*, 362 U.S. 99, 123-24 (1960). Similarly, Congress included the same eminent domain authority for permit holders for electric transmission facilities when it enacted the Energy Policy Act of 2005. 16 U.S.C. § 824p(e)(1) (2012).

[124] The FTC has not filed comments.

[125] November 4, 2016 response at 18.

[126] *See NAACP v. FPC*, 425 U.S. 662, 670, n.6. (1976) (citations omitted) (stating that "the Commission has authority to consider conservation, environmental, and antitrust questions").

Atlantic states that case-specific hydraulics, along with the location of receipt and delivery points, dictate the appropriate location of compression facilities. Atlantic asserts that its system is designed for a specific situation, and therefore, the distance between compressor stations will vary from the general ranges cited by Mr. Laska.

85. Based upon its review of the pipeline design, hydraulic models, and explanation of how the location of compressor stations are determined, Commission staff determined that Atlantic has properly designed its pipeline system based upon design and location constraints. Mr. Laska's allegations that the pipeline is over-built because of the distances between compressor stations exceed the typical range of 40 to 100 miles apart does not take into consideration the specific transportation requirements nor the design and operating conditions that are unique to the project.

B. Blanket Certificates

86. Atlantic requests a Part 284, Subpart G blanket certificate in order to provide open-access transportation services. Under a Part 284 blanket certificate, Atlantic will not require individual authorizations to provide transportation services to particular customers. Atlantic filed a *pro forma* Part 284 tariff to provide open-access transportation services. Since a Part 284 blanket certificate is required for Atlantic to offer these services, we will grant Atlantic a Part 284 blanket certificate, subject to the conditions imposed herein.

87. Atlantic has also applied for a Part 157, Subpart F blanket certificate. The Part 157 blanket certificate gives an interstate pipeline NGA section 7 authority to automatically, or after prior notice, perform certain activities related to the construction, acquisition, abandonment, and replacement and operation of pipeline facilities. Because Atlantic will become an interstate pipeline with the issuance of a certificate to construct and operate the proposed facilities, we will issue to Atlantic the requested Part 157, Subpart F blanket certificate.

C. Lease Agreement

88. As described above, Atlantic and Piedmont have entered into a Capacity Lease Agreement whereby Atlantic will lease 100,000 Dth/d of capacity on Piedmont's system and use the leased capacity to provide service under the terms of its FERC Tariff.

89. Historically, the Commission views lease arrangements differently from transportation services under rate contracts. The Commission views a lease of interstate pipeline capacity as an acquisition of a property interest that the lessee acquires in the capacity of the lessor's pipeline.[127] To enter into a lease agreement, the lessee generally

[127] *Texas Eastern Transmission Corp.*, 94 FERC ¶ 61,139, at 61,530 (2001).

needs to be a natural gas company under the NGA and needs section 7(c) certificate authorization to acquire the capacity. Once acquired, the lessee in essence owns that capacity and the capacity is subject to the lessee's tariff. The leased capacity is allocated for use by the lessee's customers. The lessor, while it may remain the operator of the pipeline system, no longer has any rights to use the leased capacity.[128]

90. The Commission's practice has been to approve a lease if it finds that: (1) there are benefits from using a lease arrangement; (2) the lease payments are less than, or equal to, the lessor's firm transportation rates for comparable service over the terms of the lease on a net present value basis; and (3) the lease arrangement does not adversely affect existing customers.[129] The lease agreement between Atlantic and Piedmont satisfies these requirements.

91. First, the Commission has found that capacity leases in general have several potential public benefits. Leases can promote efficient use of existing facilities, avoid construction of duplicative facilities, reduce the risk of overbuilding, reduce costs, minimize environmental impacts, and result in administrative efficiencies for shippers.[130] Here, the lease arrangement will provide Atlantic the ability to serve markets in North Carolina without construction of duplicative facilities which would essentially parallel the Piedmont system. The leased capacity allows for the efficient use of the available capacity on Piedmont, avoids the environmental impact and impacts on landowners associated with constructing duplicative facilities, substantially reduces the costs of constructing Atlantic's system, and allows Atlantic's system to be placed into service earlier than if redundant facilities were constructed. The lease will provide Atlantic's shippers with seamless access, under a single firm transportation contract, from the Appalachian Basin to delivery points in North Carolina.

92. Second, Atlantic states that the monthly lease charge it will pay to Piedmont is less than Piedmont's maximum applicable transportation rates for comparable service. Piedmont states that comparable transportation service is offered under Rate Schedule 113, which has an annual average daily rate of $0.23 per Dth.[131] According to Atlantic

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[128] *Texas Gas Transmission, LLC*, 113 FERC ¶ 61,185, at P 10 (2005).

[129] *Id.*; *Islander East Pipeline Co., L.L.C.*, 100 FERC ¶ 61,276, at P 69 (2002).

[130] *See, e.g., Dominion Transmission, Inc.*, 104 FERC ¶ 61,267, at P 21 (2003); *Islander East Pipeline Co. L.L.C.*, 100 FERC ¶ 61,276 at P 70.

[131] In Rate Schedule 113, Piedmont offers two seasonal rates, a summer rate and a winter rate. For our analysis of the lease payments, we used an average daily rate based on the entire year.

and Piedmont's October 3, 2016 data response, Atlantic will make a monthly payment of $228,125 to Piedmont for the leased capacity of 100,000 Dth/d. This equates to a daily demand charge of $0.075 per Dth, which is lower than the rate for comparable transportation service on Piedmont's system.

93. Third, the lease will use existing capacity on Piedmont's system and will not adversely affect Piedmont's existing customers. Piedmont's existing customers will not subsidize the costs of providing capacity for Atlantic, and Piedmont states that it will not pass on any costs associated with the lease to its existing customers.[132] In addition, the North Carolina Utilities Commission has authorized Piedmont to enter into the lease in an order issued October 28, 2014.[133]

94. Because the lease payments are satisfactory, there are significant benefits, and those benefits outweigh any potential harm to Piedmont's customers, we find that the proposed lease is required by the public convenience and necessity.

95. To enable Piedmont to carry out its responsibilities under the lease agreement, we will issue Piedmont a limited jurisdiction certificate. The Commission looks closely at proposals that would create dual jurisdiction facilities, i.e., facilities that would be subject to state and federal jurisdiction, in order to avoid duplicative and/or potentially inconsistent regulatory schemes over the same facilities. However, here, although federal regulation of Piedmont will be "limited," Piedmont and Atlantic will both be subject to exclusive federal regulation regarding the lease of 100,000 Dth/d of capacity on the Piedmont system and any issues that may arise thereunder. The limited jurisdiction certificate will enable Piedmont to operate the leased capacity being used for NGA jurisdictional services subject to the terms of the lease and subject to Atlantic's open-access tariff.[134] The limited jurisdiction certificate will require Piedmont to operate the leased capacity in a manner that ensures Atlantic's ability to provide services, including interruptible transportation, using the leased capacity on an open-access, non-

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[132] Atlantic and Piedmont's Joint Application at 13.

[133] "Order Accepting Affiliated Agreements For Filing and Permitting Operation Thereunder Pursuant to G.S. 62-153 and Authorizing Piedmont to Enter into Related Redelivery Agreements," issued by the NCUC in its Docket No. G-9, Sub 655, on Oct. 28, 2014.

[134] Atlantic and Piedmont also request a waiver of the Commission's "shipper must have title" rule to allow Atlantic to transport gas on the leased Piedmont capacity for Atlantic's customers using gas owned by those customers. This waiver is not necessary as the leased capacity will now be considered part of Atlantic's system and is subject to the terms and conditions of Atlantic's tariff.

discriminatory basis. We have approved similar leases in the past involving intrastate pipelines and local distribution companies,[135] and our finding that Piedmont is NGA-jurisdictional is limited to its role as lessor-operator of capacity used by Atlantic to provide Atlantic's interstate services. Piedmont will remain non-jurisdictional as to its intrastate activities.

96. We will require Atlantic to file with the Commission a notification in this docket, within 10 days of the date of acquisition of the capacity leased from Piedmont, providing the effective date of the acquisition.[136] We also remind the applicants that when the lease terminates, Atlantic is required to obtain authority to abandon the leased capacity.[137]

D. Rates

1. Atlantic Coast Pipeline Project

a. Atlantic's Initial Rates

97. Atlantic proposes to provide firm (Rate Schedule FT) and interruptible (Rate Schedule IT) transportation services under Part 284 of the Commission's regulations at cost-based recourse rates, and also requests the authority to offer service at negotiated rates. Atlantic proposes a maximum FT reservation recourse rate of $1.7249 per Dth and a FT commodity charge of $0.0041 per Dth.[138] The maximum IT recourse rate of $1.7290 per Dth is based on the maximum daily FT reservation rate plus the FT commodity charge.[139] Atlantic states that it designed its initial recourse rates consistent

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[135] *See, e.g., The East Ohio Gas Co.*, 133 FERC ¶ 61,076 (2010).

[136] *Nexus Gas Transmission, LLC*, 160 FERC ¶ 61,022, at P 70 (2017).

[137] *Transcontinental Gas Pipe Line Company, LLC*, 156 FERC ¶ 61,092, at P 57 (2016).

[138] Atlantic proposes to include in its Statement of Applicable Rates, on *pro forma* tariff record 10.20, the applicable DETI rates that will be assessed to customers utilizing the capacity Atlantic contracted on the DETI Supply Header Project, pursuant to section 29 (Off-System Capacity) of the General Terms & Conditions (GT&C).

[139] Atlantic states that its fuel retention percentage will be adjusted on a quarterly basis and that any over- or under- recoveries of fuel will be tracked and flowed through in future period fuel retention percentages, pursuant to GT&C section 31. Atlantic states that it will submit a tariff filing 30 to 60 days prior to going into service to establish its initial Transportation Fuel Retainage Percentage, which is currently stated as "TBD" in its *pro forma* tariff.

with the Straight-Fixed Variable rate design methodology based on the full design capability of 1,500,000 Dth/d and first-year cost of service of $946,320,533. Atlantic developed its proposed first year cost of service utilizing a capital structure of 50 percent debt and 50 percent equity, with a debt cost of 6.8 percent, a return on equity (ROE) of 14 percent, and a depreciation rate of 2.5 percent.

98. The NCUC states that Atlantic has failed to provide any analysis of current financial markets and/or current investor expectations to justify the proposed 14 percent ROE.[140] The NCUC suggests that it would not be reasoned decision-making to establish recourse rates for over $5.1 billion of investment without requiring Atlantic to comply with its statutory obligation of demonstrating that its proposed project is required by the public convenience and necessity based on current market conditions.[141] The NCUC asserts that Atlantic's first-year pre-tax return of 15 percent accounts for approximately three quarters of Atlantic's first-year cost of service and the ROE chosen to compute the recourse rates has a material impact on those rates.[142] Further, the NCUC suggests that the cases cited by Atlantic in its application are not as relevant as the Commission's more recent Opinion No. 524-A, where the Commission reaffirmed a decision using a discounted cash flow analysis that resulted in a median ROE of 10.28 percent.[143] The NCUC cited a number of other cases in which the Commission approved ROEs much lower than 14 percent;[144] however, the NCUC also recognizes that the ROEs approved in those cases were for existing pipeline companies rather than new companies such as Atlantic.[145]

99. Many commenters also cite the IEEFA Study, which concludes that the Commission policy allowing an ROE of 14 percent for new pipeline construction leads to overbuilding of pipelines because the ROE is higher than that of other regulated utilities.

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[140] NCUC Protest at 6.

[141] *Id.*

[142] *Id.* (citing Atlantic Initial Application at Exhibit P, Page 3, Lines 8-9).

[143] *Portland Natural Gas Transmission Sys.*, Opinion No. 524-A, 150 FERC ¶ 61,107, at P 195 (2015).

[144] *El Paso Natural Gas Co.*, Opinion No. 528, 145 FERC ¶ 61,040, at P 686 (2013); *Portland Natural Gas Transmission Sys.,* Opinion No. 510-A, 142 FERC ¶ 61,198, at P 250 (2013), *order on reh'g*, 150 FERC ¶ 61,106 (2015); *Kern River Gas Transmission Co.,* Opinion No. 486-F, 142 FERC ¶ 61,132, at P 263 (2013).

[145] NCUC Protest at 7.

The IEEFA Study notes that the average ROE granted by state public utilities commissions to investor-owned electric utilities was 9.92 percent and the Commission recently lowered its allowed return on equity for electric transmission companies in New England to a maximum of 11.74 percent. The IEEFA Study also notes that a study by the Natural Gas Supply Association found that a majority of pipeline companies earned returns on equity greater than 12 percent, with two of those companies earning returns on equity in excess of 24 percent.

100. In its answer, Atlantic states that the NCUC provides no basis for Atlantic to be treated differently than all other new pipeline projects approved in recent years. Additionally, Atlantic asserts that the Commission has never found that changed financial conditions over the past ten years have warranted a reduction in the ROE allowed for new pipelines, which stands at 14 percent.[146] Atlantic reiterates that its proposed 14 percent ROE reflects the construction, financial, regulatory, and contractual risks faced by new pipelines and few of the approved cases spanning the past decade contain the sort of "analysis of current financial markets and/or current investor expectations" that the NCUC seeks.[147]

101. In section 7 certificate proceedings, the Commission reviews initial rates for service using proposed new pipeline capacity under the public convenience and necessity standard, which is a less rigorous standard than the just and reasonable standard under NGA sections 4 and 5.[148] The Commission does not believe that conducting a discounted

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[146] Atlantic Initial Application at 30 n.24. *See, e.g., Constitution Pipeline Co., LLC*, 149 FERC ¶ 61,199, at PP 48-49 (2014) (50/50 capital structure and ROE 14%); *Sierrita Gas Pipeline, LLC*, 147 FERC ¶ 61,192, at P 39 n.28 (2014) (70/30 capital structure and ROE 14%); *Ruby Pipeline L.L.C.*, 136 FERC ¶ 61,054, at P 11 (2011) (50/50 capital structure and ROE 14%).

[147] Atlantic Answer at 25-26.

[148] *Atlantic Refining Co. v. Public Serv. Comm'n of New York*, 360 U.S. 378 (1959) (*CATCO*). In *CATCO*, the Court contrasted the Commission's authority under sections 4 and 5 of the NGA to approve changes to existing rates using existing facilities and its authority under section 7 to approve initial rates for new services and services using new facilities. The Court recognized "the inordinate delay" that can be associated with a full-evidentiary rate proceeding and concluded that was the reason why, unlike sections 4 and 5, section 7 does not require the Commission to make a determination that an applicant's proposed initial rates are or will be just and reasonable before the Commission certificates new facilities, expansion capacity, and/or services. *Id.* at 390. The Court stressed that in deciding under section 7(c) whether proposed new facilities or services are required by the public convenience and necessity, the Commission is required to "evaluate all factors bearing on the public interest," and noted that an

cash flow analysis in individual certificate proceedings would be the most effective or efficient way for determining the appropriate ROE. While parties have the opportunity in section 4 rate proceedings to file and examine testimony with regard to the composition of the proxy group to use in a discounted cash flow analysis, the growth rates used in the analysis, and the pipeline's position within the zone of reasonableness with regard to risk, it would be difficult, if not impossible, to complete this type of analysis in section 7 certificate proceedings in a timely manner, and attempting to do so would unnecessarily delay proposed projects with time sensitive in-service schedules.[149]

102. As noted by Atlantic, in prior cases, the Commission has allowed a 14 percent ROE for greenfield pipeline projects based on a capital structure that contains no more than 50 percent equity. The Commission's policy of approving equity returns of up to 14 percent with an equity capitalization of no more than 50 percent reflects the fact that greenfield pipelines undertaken by a new entrant in the market face higher business risks than existing pipelines proposing incremental expansion projects.[150] Thus, approving Atlantic's requested 14 percent return on equity in this instance is not merely "reflexive"; it is in response to the risk Atlantic faces as a new market entrant, constructing a new greenfield pipeline system. Moreover, the returns approved for electric utilities and local distribution companies are not relevant because there is no showing that these companies face the same level of risk as faced by greenfield projects proposed by a new natural gas pipeline company.[151]

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applicant's proposed initial rates are not "the only factor bearing on the public convenience and necessity." *Id.* at 391. Thus, as explained by the Court, "[t]he Congress, in § 7(e), has authorized the Commission to condition certificates in such manner as the public convenience and necessity may require when the Commission exercises authority under section 7," *id.*, and the Commission therefore has the discretion in section 7 certificate proceedings to approve initial rates that will "hold the line" and "ensure that the consuming public may be protected" while awaiting adjudication of just and reasonable rates under the more time-consuming ratemaking sections of the NGA. *Id.* at 392.

[149] *Id.* at 391.

[150] *See, e.g.*, *Rate Regulation of Certain Natural Gas Storage Facilities,* Order No. 678, FERC Stats. & Regs. ¶ 31,220, at P 127 (2006) (explaining that existing pipelines who need only acquire financing for incremental expansions face less risk than "a greenfield project undertaken by a new entrant in the market").

[151] The Commission has previously concluded that distribution companies are less risky than a pipeline company. *See, e.g. Trailblazer Pipeline Co.,* 106 FERC ¶ 63,005, at

103. Further, as explained below, we are requiring Atlantic to file a cost and revenue study at the end of its first three years of actual operation to justify its existing cost-based rates. The three-year study will provide an opportunity for the Commission and the public to review Atlantic's original estimates, upon which its initial rates are based, to determine whether Atlantic is over-recovering its cost of service with its approved initial rates, and whether the Commission should exercise its authority under section 5 of the NGA to establish just and reasonable rates. Alternatively, Atlantic may elect to make a NGA section 4 filing to revise its initial rates. The public would have an opportunity to review Atlantic's proposed return on equity and other cost of service components at that time and would have an opportunity to raise issues relating to the rate of return, as well as all other cost components. As such, we find that Atlantic's proposed rates will "ensure that the consuming public may be protected" until just and reasonable rates can be determined through the more thorough and time-consuming ratemaking sections of the NGA.[152]

104. We have reviewed Atlantic's proposed cost of service and initial rates and find they reasonably reflect current Commission policy for a new pipeline entity. Therefore, we accept Atlantic's proposed recourse rates as the initial rates for service on its pipeline.

b. Three-Year Filing Requirement

105. Consistent with Commission precedent, Atlantic is required to file a cost and revenue study no later than three months after the end of its first three years of actual operation to justify its initial cost-based firm and interruptible recourse rates.[153] In its filing, the projected units of service should be no lower than those upon which Atlantic's approved initial rates are based. The filing must include a cost and revenue study in the form specified in section 154.313 of the Commission's regulations to update cost of service data.[154] Atlantic's cost and revenue study should be filed through the eTariff portal using a Type of Filing Code 580. In addition, Atlantic is advised to include, as part of the eFiling description, a reference to Docket No. CP15-554-000 and the cost and

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P 94 (2004) (rejecting inclusion of local distribution companies in a proxy group because they face less risk than a pipeline company.).

[152] *CATCO*, 360 U.S. at 392.

[153] *Rover Pipeline, LLC*, 158 FERC ¶ 61,109, at P 82 (2017); *Ruby Pipeline, L.L.C.*, 128 FERC ¶ 61,224, at P 57 (2009); *MarkWest Pioneer, L.L.C.*, 125 FERC ¶ 61,165, at P 34 (2008).

[154] 18 C.F.R. § 154.313 (2017).

revenue study.[155] After reviewing the data, the Commission will determine whether to exercise its authority under NGA section 5 to investigate whether the rates remain just and reasonable. In the alternative, in lieu of this filing, Atlantic may make a general NGA section 4 rate filing to propose alternative rates to be effective no later than three years after the in-service date for its proposed facilities.

2. DETI Supply Header Project

106. DETI proposes to establish as its recourse rates an initial monthly incremental transportation base reservation charge of $4.7459 per Dth and its existing system maximum base usage charge of $0.0083 per Dth.[156] The reservation charge was based on a first year cost of service of $86,072,419 and full design capacity of 1,511,335 Dth/d.[157] In developing its first year cost of service, DETI uses a pre-tax return of 13.70 percent and its system depreciation rate of 2.5 percent, which DETI states were approved in a settlement in Docket No. RP97-406-000.[158] Further, DETI plans to charge all other applicable rates, charges, and surcharges under its Rate Schedule FT, including its Transportation Cost Rate Adjustment and Electric Power Cost Adjustment charges, the maximum usage charge, and maximum system fuel retention percentage.

107. The NCUC protested DETI's proposed recourse rates stating DETI has not demonstrated that use of a pre-tax return of 13.70 percent to calculate its proposed recourse rates is reflective of current financial market conditions. The NCUC believes the use of a pre-tax return from a rate case filed over 15 years ago means that a major element of the proposed recourse rates does not reflect current costs.[159] The NCUC asserts that DETI's first-year pre-tax return of 13.70 percent will be over three quarters of DETI's cost of service underlying the proposed recourse rates, and because DETI simply followed the Commission's policy of using the last return on file without regard to whether the pre-tax return reflects current market conditions, DETI's application is devoid of any evidence which would permit an analysis of the majority of the cost of service underlying its proposed recourse rates. The NCUC asserts that application of the Commission's policy may result in reasonable recourse rates when a pipeline's rate of

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[155] *Electronic Tariff Filings*, 130 FERC ¶ 61,047, at P 17 (2010).

[156] DETI March 15, 2016 Data Response at Question 5.

[157] DETI March 15, 2016 Data Response, Question 5 at Page 3 of Attachment 2.

[158] *CNG Transmission Corp.*, 85 FERC ¶ 61,261, at 62,051 (1998).

[159] NCUC Protest at 7.

return, debt costs, and capital structure were recently, or are being concurrently, reviewed; however, that is not the case here.

108. The NCUC states financial markets are very different now than when DETI's ROE was last approved and that the Commission's most recent pronouncements on ROE provide valuable perspective on the reasonableness of DETI's proposed 13.70 percent pre-tax return. For example, the NCUC points out that the Commission recently reaffirmed a decision using a discounted cash flow analysis, based on the six-month period ending March 31, 2011, which resulted in a median ROE of 12.08 percent.[160] In addition, the NCUC states the Commission has approved an ROE of 10.55 percent for El Paso Natural Gas Company, 12.99 percent for Portland Natural Gas Transmission System, and 11.55 percent for Kern River Gas Transmission Company.[161] The NCUC recognizes that these ROEs are not directly comparable to the pre-tax return proposed by DETI; however, the lack of specified ROE, debt costs, and capital structure in DETI's application precludes any apples-to-apples comparison.

109. In its answer, DETI states that it has developed a large number of projects on its system with incremental rates and the Commission has consistently approved the 13.70 percent pre-tax rate of return. DETI asserts that the use of the pre-tax return follows well-established Commission policy and the Commission has considered and rejected the same argument advanced by the NCUC with regards to DETI's Allegheny Storage Project.[162]

110. As the NCUC acknowledges, the Commission's consistent policy in section 7 certificate proceedings is to require that a pipeline's cost-based recourse rates for incrementally-priced expansion capacity be designed using the rate of return from its most recent general rate case approved by the Commission under section 4 of the NGA in which a specified rate of return was used to calculate the rates.[163] DETI's proposed

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[160] *Portland Natural Gas Transmission Sys.*, Opinion No. 524-A, 150 FERC ¶ 61,107 at P 195.

[161] *El Paso Natural Gas Co.*, Opinion No. 528, 145 FERC ¶ 61,040 at P 686; *Portland Natural Gas Transmission Sys.*, Opinion No. 510-A, 142 FERC ¶ 61,198 at P 250, *order on reh'g*, 150 FERC ¶ 61,106; and *Kern River Gas Transmission Co.*, Opinion No. 486-F, 142 FERC ¶ 61,132 at P 263.

[162] *Dominion Transmission, Inc.*, 141 FERC ¶ 61,240 at P 41.

[163] *See, e.g., Trunkline Gas Co., LLC*, 135 FERC ¶ 61,019, at P 33 (2011); *Florida Gas Transmission Co., LLC*, 132 FERC ¶ 61,040, at P 35 n.12 (2010); *Northwest Pipeline Corp.*, 98 FERC ¶ 61,352, at 62,499 (2002); and *Mojave Pipeline Co.*, 69 FERC ¶ 61,244, at 61,925 (1994). *See also Dominion Cove Point LNG, LP*,

incremental recourse rate for the Supply Header Project is based on the specified pre-tax return of 13.70 percent underlying the design of its approved settlement rates in Docket No. RP97-406-000.[164] While DETI has twice entered into settlements with its customers reaffirming its rates while providing certain rate relief, neither of those settlements specified the rate of return or most other cost of service components used to calculate the settlement rates.[165] Therefore, DETI calculated its proposed incremental rates in this certificate proceeding consistent with Commission policy by using the last Commission-approved specified pre-tax return.

111. The Commission's current policy of calculating incremental rates for expansion capacity using the Commission-approved ROEs underling pipelines' existing rates is an appropriate exercise of its discretion in section 7 certificate proceedings to approve initial rates that will "hold the line" until just and reasonable rates are adjudicated under section 4 or 5 of the NGA.[166] As discussed above, we do not believe that conducting discounted cash flow analyses in individual certificate proceedings would be the most effective or efficient way for determining the appropriate ROEs for proposed pipeline expansions.

112. DETI's proposed incremental monthly recourse reservation charge of $4.7459 per Dth is higher than the generally applicable Rate Schedule FT reservation

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115 FERC ¶ 61,337, at P 132 (2006), *order on reh'g,* 118 FERC ¶ 61,007, at PP 120, 122-123 (2007) (allowing, on rehearing, Dominion Cove Point LNG to recalculate incremental rates using the rates of return ultimately approved in its pending rate case, as opposed to its proposed rates of return). If a pipeline's most recent general section 4 rate case involved a settlement that did not specify a rate of return or pre-tax return, the Commission's policy requires that incremental rates in the pipeline's certificate proceedings be calculated using the rate of return or pre-tax return from its most recent general section 4 rate case (or rate case settlement) in which a specified return component was used to calculate the approved rates. *See, e.g.*, *Equitrans, L.P.*, 117 FERC ¶ 61,184, at P 38 (2006). This policy applies even if a pipeline calculated its proposed incremental rates for expansion capacity using a rate of return *lower* than the most recently approved specified rate of return. *Id.* (rejecting Equitrans's proposed use of 14.25 percent ROE component for incremental rates for mainline extension and requiring recalculation using the specified pre-tax rate of return of 15 percent that was approved in its rate case).

[164] *CNG Transmission Corp.*, 85 FERC ¶ 61,261 at 62,051.

[165] *See Dominion Transmission, Inc.*, 146 FERC ¶ 61,068 (2014); *Dominion Transmission, Inc.*, 111 FERC ¶ 61,285 (2005).

[166] *See Transcontinental Gas Pipe Line Co.*, 156 FERC ¶ 61,092 at PP 26-29; *Transcontinental Gas Pipe Line Co.*, 156 FERC ¶ 61,022, at PP 23-26 (2016).

charge of $3.8820 per Dth contained in DETI's tariff. Additionally, DETI's proposes to use its existing system maximum base usage charge of $0.0083 per Dth.[167] We find that DETI's proposed recourse rates are consistent with the Certificate Policy Statement and therefore approve them as the initial recourse rates for firm service using the incremental capacity created by the project.

113. DETI proposes to charge its system-wide fuel retention rate for the project. In order to ensure that existing shippers do not subsidize the project, DETI provided a fuel study which shows that the total estimated fuel used by the project facilities during the Summer Design Day[168] is 9,300 Dth. Using DETI's current fuel retention rate of 1.95 percent for the total Maximum Daily Transportation Quantity (MDTQ) of 1,511,335 Dth results in a total daily fuel retention of 30,057 Dth. The total daily fuel retention exceeds the projected maximum daily fuel used by the project facilities; consequently no subsidization by existing customers will occur and DETI's proposal to charge its system-wide fuel retention rate is appropriate.

114. We will require DETI to keep separate books and accounting of costs and revenues attributable to the proposed incremental services and capacity created by the Supply Header Project as required by section 154.309 of the Commission's regulations. The books should be maintained with applicable cross-reference as required by section 154.309. This information must be in sufficient detail so that the data can be identified in Statements G, I, and J in any future NGA section 4 or 5 rate case, and the information must be provided consistent with Order No. 710.[169]

3. <u>Negotiated Rates</u>

115. DETI and Atlantic propose to provide service to their shippers under negotiated rate agreements. DETI and Atlantic must file either their negotiated rate agreements or tariff records setting forth the essential elements of the agreements in accordance with the Alternative Rate Policy Statement[170] and the Commission's negotiated rate policies.[171]

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[167] DETI March 15, 2016 Data Response at Question 5.

[168] The Summer Design Day is used to determine the incremental fuel because DETI projects it to be the day that will have the highest daily fuel usage by the project's facilities.

[169] 18 C.F.R. § 154.309 (2017).

[170] *Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines; Regulation of Negotiated Transportation Services of Natural Gas Pipelines*, 74 FERC ¶ 61,076, *order granting clarification*, 74 FERC ¶ 61,194, *order on reh'g and clarification*, 75 FERC ¶ 61,024, *reh'g denied*, 75 FERC ¶ 61,066, *reh'g dismissed*,

DETI and Atlantic must file the negotiated rate agreements or tariff records at least 30 days, but no more than 60 days, before the proposed effective date for such rates.

E. Non-Conforming Contract Provisions

116. Atlantic and DETI entered into precedent agreements that contained certain contractual rights not available to other customers, which they state may be viewed as material deviations, but are necessary incentives to secure the level of contractual commitments to develop the projects. Atlantic and DETI request that the Commission approve these non-conforming contract provisions.

117. If a pipeline and a shipper enter into a contract that materially deviates from the pipeline's form of service agreement, the Commission's regulations require the pipeline to file the contract containing the material deviations with the Commission.[172] In *Columbia Gas Transmission Corp.*, the Commission clarified that a material deviation is any provision in a service agreement that: (1) goes beyond filling in the blank spaces with the appropriate information allowed by the tariff and (2) affects the substantive rights of the parties.[173] The Commission prohibits negotiated terms and conditions of service that result in a shipper receiving a different quality of service than that offered other shippers under the pipeline's generally applicable tariff or that affect the quality of service received by others.[174] However, not all material deviations are impermissible. As the Commission explained in *Columbia*, provisions that materially deviate from the corresponding *pro forma* agreement fall into two general categories: (1) provisions the Commission must prohibit because they present a significant potential for undue discrimination among shippers and (2) provisions the Commission can permit without a

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75 FERC ¶ 61,291 (1996), *petition denied sub nom. Burlington Res. Oil & Gas Co. v. FERC*, 172 F.3d 918 (D.C. Cir. 1998) (Alternative Rate Policy Statement).

[171] *Natural Gas Pipeline Negotiated Rate Policies and Practices; Modification of Negotiated Rate Policy*, 104 FERC ¶ 61,134 (2003), *order on reh'g and clarification*, 114 FERC ¶ 61,042, *dismissing reh'g and denying clarification*, 114 FERC ¶ 61,304 (2006).

[172] 18 C.F.R. §§ 154.1(d), 154.112(b) (2017).

[173] *Columbia Gas Transmission Corp.*, 97 FERC ¶ 61,221, at 62,002 (2001) (*Columbia*).

[174] *Monroe Gas Storage Co., LLC*, 130 FERC ¶ 61,113, at P 28 (2010).

substantial risk of undue discrimination.[175] In other proceedings, we have also found that non-conforming provisions may be necessary to reflect the unique circumstances involved with constructing new infrastructure and to provide the needed security to ensure the viability of a project.[176]

118. As discussed below, with the exception of Atlantic's special no-notice service, we find that Atlantic's and DETI's proposals are permissible material deviations. At least 30 days, but not more than 60 days, before providing service to any project shipper under a non-conforming service agreement, Atlantic and DETI must file an executed copy of their non-conforming service agreements and identify and disclose all non-conforming provisions or agreements affecting the substantive rights of the parties under the tariff or service agreement. This required disclosure includes any such transportation provision or agreement detailed in a precedent agreement that survives the execution of the service agreement. Consistent with section 154.112 of the Commission's regulations, Atlantic and DETI must also file a tariff record identifying the agreements as non-conforming agreements.[177] In addition, the Commission emphasizes that the above determination relates only to those items identified by Atlantic and DETI and not to the entirety of the precedent agreements or the language contained in the precedent agreements.[178]

1. <u>Atlantic</u>

119. Atlantic entered into precedent agreements with two categories of shippers: Foundation Shippers and Anchor Shippers.[179] Atlantic states that its Foundation and

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[175] *Columbia*, 97 FERC at 62,003-04. *See also Equitrans, L.P.*, 130 FERC ¶ 61,024, at P 5 (2010).

[176] *Midcontinent Express Pipeline LLC*, 124 FERC ¶ 61,089, at P 82 (2008); *Rockies Express Pipeline LLC*, 116 FERC ¶ 61,272, at P 78 (2006).

[177] 18 C.F.R. § 154.112 (2017).

[178] A Commission ruling on non-conforming provisions in a certificate proceeding does not waive any future review of such provisions when the executed copy of the non-conforming agreement(s) and a tariff record identifying the agreement(s) as non-conforming are filed with the Commission, consistent with section 154.112 of the Commission's regulations. *See, e.g.*, *Tennessee Gas Pipeline Co., L.L.C.*, 150 FERC ¶ 61,160, at P 44 n.33 (2015).

[179] A Foundation Shipper is defined as a shipper that contracts for at least 300,000 Dth/d of firm transportation capacity for a term of at least 20 years, and an Anchor Shipper is defined as a shipper that contracts for at least 150,000 Dth/d, but less than 300,000 Dth/d, for a term of at least 20 years. Atlantic Initial Application at 13.

Anchor Shippers have been granted certain contractual rights not available to other customers, which may be viewed as material deviations, but are necessary incentives to secure the level of contractual commitments to develop the project. In particular, Atlantic identifies six provisions as non-conforming: (a) contract extension rights and a contractual right of first refusal (ROFR); (b) expansion rights; (c) special no-notice service via a "pack account"; (d) reduction rights; and (f) DETI capacity rights.[180] Atlantic states that all prospective customers were given the opportunity to become a Foundation or Anchor Shipper through the open season process.

120. As discussed more fully below, we find the (1) contract extension rights; (2) reduction rights; (3) DETI capacity rights; and (4) expansion rights to be permissible material deviations from Atlantic's *pro forma* service agreements. However, as proposed, the special no-notice service via a "pack account" is not a permissible material deviation.

a. Extension Rights and Reduction Rights

121. Atlantic has provided its Foundation and Anchor Shippers with a contractual right to extend their initial 20-year primary term contracts by additional five-year extension periods, which may be exercised up to four times per Article III.A of the precedent agreements. At the end of the final five-year extension period, Atlantic has provided shippers with a contractual ROFR per General Terms and Conditions section 25 of Atlantic's *pro forma* tariff. Atlantic has also provided Foundation Shippers with a right to specify a reduction in their MDTQs to be applied upon commencement of each extended five-year term.

122. The Commission has approved non-conforming provisions that reflect the unique circumstances involved with the construction of new infrastructure and provide the needed security to ensure that the project gets built.[181] Here, Atlantic states that these provisions were necessary to ensure contractual commitments without which the project could not go forward. We find these rights are permissible because they do not present a risk of undue discrimination, do not affect the operational conditions of providing service, and do not result in any customer receiving a different quality of service.[182]

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[180] Atlantic provided public versions of the *pro forma* service agreements in redline/strikeout identifying the non-conforming language verbatim in its August 19, 2016 data response.

[181] *See, e.g.*, *Tennessee Gas Pipeline Co. L.L.C.*, 144 FERC ¶ 61,219, at PP 26-33 (2013); *Rockies Express Pipeline, LLC*, 116 FERC ¶ 61,272 at PP 74-78.

[182] *Tennessee Gas Pipeline Co L.L.C.*, 144 FERC ¶ 61,219 at P 32.

b. **DETI Capacity Rights**

123. Prior to the termination date of Atlantic's firm transportation service agreement with DETI, Atlantic will determine if any initial shipper elects to extend its DETI capacity right, and if so, Atlantic will contract with DETI accordingly. If any initial shipper elects not to maintain its DETI capacity rights, such rights will be removed from the affected service agreements. We find that the DETI capacity rights provision is not unduly discriminatory because General Terms and Conditions section 29.2.A of Atlantic's *pro forma* tariff provides all firm transportation shippers the same rights. Therefore, we find these rights are permissible because they do not present a risk of undue discrimination, do not affect the operational conditions of providing service, and do not result in any customer receiving a different quality of service.

c. **Expansion Rights**

124. Exhibit A of the Foundation Shipper precedent agreements contains contractual incentives for the shippers to request that Atlantic undertake an expansion of its system at any time between the in-service date of the initial pipeline project and the fourth anniversary of such date.[183] Foundation and Anchor Shippers will have a one-time option to elect to contract for an additional quantity up to one-third of their MDTQs, for a new 20-year term, in the first expansion of the pipeline. Atlantic has also agreed, in Exhibit B of the applicable precedent agreements, upon the rate methodology to be used in calculating charges for the optional capacity to be charged to the Foundation and Anchor Shippers for the requested optional incremental expansion service. Atlantic also provides, in Exhibit A, Part 4 of the Foundation Shipper precedent agreements, that Foundation Shippers have the right to request that Atlantic consider undertaking a second expansion either (1) at the time of Customer's election of Optional Quantities or (2) after the date of a Commission order concerning the expansion that creates the capacity to transport the Optional Quantities and during the primary term of its Service Agreement. Atlantic states that at such time as the Foundation Shipper requests a second expansion, Atlantic shall determine the scope, design, and estimated costs and rates (calculated pursuant to the cost-of-service methodology described in Exhibit C) of the second expansion project.

125. The NCUC states that it is not clear whether Atlantic will roll-in the costs of subsequent inexpensive expansions for purposes of calculating recourse rates and requests that the Commission clarify that nothing in Atlantic's application exempts

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[183] Atlantic has also afforded Anchor Shippers, in Exhibit A of their precedent agreements, the ability to participate in the first expansion once a Foundation Shipper initiates such a request; however an Anchor Shipper cannot trigger the timing of such expansion. Atlantic Initial Application at 27-28.

Atlantic from complying with Commission policy requiring roll-in of inexpensive expansion capacity for purposes of calculating recourse rates.[184]

126. Atlantic states that the NCUC's request that the Commission rule now that Atlantic must roll in the costs of potential future expansions is premature. Atlantic states that it does not propose to be exempt from any Commission policy for pricing service utilizing inexpensive expansion capacity.[185] Atlantic concludes that there is no basis to determine now how recourse rates should be calculated in the event that additional capacity is added at an unknown future date.[186]

127. The Commission has found that giving project sponsors certain priority rights to future expansion capacity is a permissible material deviation from the *pro forma* service agreement because such provision reflects the unique circumstances of the initial project.[187] As the Commission discussed in *Transcontinental Gas Pipeline Co., LLC*, "where a subsequent expansion is envisioned that will be less costly due to the anchor shipper's subscription, such capacity priority is reasonable when an anchor shipper is committing to both projects and the provision was offered to all potential shippers in the open season."[188] We find Atlantic's provision to offer optional capacity to Foundation and Anchor Shippers, via an expansion, to be a contractual incentive for obtaining each shipper's binding commitments to the project. We find these rights are permissible because Atlantic offered all Anchor and Foundation shippers the expansion rights in its open season, and the expansion rights do not present a risk of undue discrimination, do not affect the operational conditions of providing service, and do not result in any customer receiving a different quality of service.

128. Further, we find that the negotiated rate calculation methodologies for the first and second expansions outlined in Exhibits B and C are permissible as they apply only to Atlantic's Foundation and Anchor shippers. Without knowing the size and costs associated with any future expansion, the Commission cannot determine if those costs should be rolled in to Atlantic's system rates in a future section 4 rate case.

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[184] NCUC Protest at 8-9.

[185] Atlantic Answer at 27.

[186] Atlantic Answer at 28.

[187] *Sierrita Gas Pipeline, LLC*, 147 FERC ¶ 61,192 at P 104.

[188] *Transcontinental Gas Pipeline Co., LLC*, 145 FERC ¶ 61,152, at P 34 (2013).

d. No-Notice Service

129. Atlantic proposes to provide its Foundation and Anchor shippers a no-notice service via a "pack account," which enables a select group of shippers to, on any gas day, tender gas quantities into an account within its MDTQ, for later delivery, as early as the next gas day, on a no-notice basis. Atlantic states that the no-notice service allows Atlantic to provide "cold start" capability to electric generation in Virginia and North Carolina. Atlantic asserts that because there are no storage capabilities on its system, to offer this service Atlantic will draw upon a substantial share of its line pack. Atlantic contends that the no-notice service ensured the viability of the project by incentivizing Anchor and Foundation shippers to commit to supporting the pipeline.

130. Under the NGA and the Commission's regulations,[189] we have consistently rejected pipeline proposals that present a significant potential for undue discrimination among similarly situated shippers.[190] Here, Atlantic proposes to offer a special no-notice service only to a select group of shippers and acknowledges that by offering this service, it is not capable of offering any park and loan service on its system to any other shipper.[191] Thus, similarly situated firm shippers are foreclosed from receiving the same level of service as Foundation and Anchor shippers on Atlantic's system. Because Atlantic's proposed no-notice service presents a significant potential for undue discrimination, we find it to be an impermissible material deviation and will require Atlantic to remove the provision from the non-conforming service agreements. If Atlantic wishes to offer this no-notice service, or a similar park and loan service, it must do so on a non-discriminatory basis through a new rate schedule.

2. DETI

131. DETI states that there are several provisions in its precedent agreement with Atlantic, its Anchor shipper, which do not conform to the *pro forma* Form of Service Agreement set forth in DETI's tariff, and DETI requests pre-approval by the Commission that the provisions are permissible material deviations.[192] Specifically, DETI's precedent

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[189] 15 U.S.C. § 717(c) (2012); 18 C.F.R. §§ 284.7(b), 284.9(b) (2017).

[190] *See Rockies Express Pipeline LLC*, 119 FERC ¶ 61,069, at P 54 (2007) (rejecting a provision that allowed the pipeline to provide a different quality of firm service to original shippers at the potential expense of future shippers).

[191] Atlantic June 2, 2017 Data Response at 3-4.

[192] DETI filed a copy of the proposed Firm Transportation Service Agreement (FT Agreement) with Atlantic identifying three non-conforming provisions.

agreement with Atlantic includes three non-conforming provisions: (1) contract extension and reduction rights; (2) delivery obligations; and (3) secondary access. DETI asserts that these terms of service reflect the unique circumstances involved with securing financial commitments necessary to support the development and construction of the project and were offered to all potential shippers through the non-discriminatory, open season bidding process for the project.

a. Extension and Reduction Rights

132. The firm transportation agreement with Atlantic includes a provision addressing extension rights, and if extended, MDTQ reduction rights that DETI states mirror the rights Atlantic provided to its own Foundation and Anchor Shippers. DETI states that these provisions were agreed upon to reflect Atlantic's use of the Supply Header capacity. Specifically, the provision provides Atlantic the right to extend the initial 20-year primary term of its agreement by additional 5-year extension periods, which may be exercised up to 4 times. Further, if Atlantic elects to extend the initial primary term, Atlantic would have the option to reduce its prospective MDTQ, with no subsequent unilateral right to increase its MDTQ.

133. The Commission has approved non-conforming provisions that reflect the unique circumstance involved with the construction of new infrastructure and provide the needed security to ensure that the project gets built.[193] Here, DETI states that these provisions were necessary to ensure contractual commitments without which the project could not go forward. Additionally, we find that the contract extension rights provision is not unduly discriminatory because it conforms to DETI's tariff, which permits DETI and a customer to mutually agree to an extension of the term of a service agreement. Therefore, we find these rights are permissible because they do not present a risk of undue discrimination, do not affect the operational conditions of providing service, and do not result in any customer receiving a different quality of service.[194]

b. Delivery Obligations

134. The firm transportation agreement also includes provisions addressing delivery obligations, including measurement, at the new Marts Junction Interconnect and the nearby Kincheloe Metering and Regulating Station.[195] Specifically, the provisions state

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[193] *See, e.g.*, *Tennessee Gas Pipeline Co.*, 144 FERC ¶ 61,219 at PP 26-33; *Rockies Express Pipeline, LLC*, 116 FERC ¶ 61,272 at PP 74-78.

[194] *Tennessee Gas Pipeline Co.*, 144 FERC ¶ 61,219 at P 32.

[195] The Kincheloe M&R Station is approximately 7.6 miles downstream from the Marts Junction Interconnect.

that the measurement at the primary delivery point (i.e., the Marts Junction Interconnect) be at the nearby Kincheloe M&R Station because the Marts Junction Interconnect is located on unsuitable terrain for the installation of measurement facilities, and DETI and Atlantic will also interconnect at the Kincheloe M&R Station. Further, the provisions provide that DETI, at its operating discretion, may deliver volumes into Atlantic at either the Marts Junction Interconnect or at the Kincheloe Interconnect and all volumes delivered by DETI to Atlantic at either of these interconnects will be treated contractually as delivered at the Marts Junction Interconnect. We find these rights are permissible because they do not present a risk of undue discrimination, do not affect the operational conditions of providing service, and do not result in any customer receiving a different quality of service.

c. Secondary Access

135. Section 6.1C of Rate Schedule FT of DETI's *pro forma* Form of Service Agreement provides for secondary access to the Applicable Market Center Point[196] on both the Access Segment[197] and Delivery Segment.[198] DETI's precedent agreement with Atlantic includes a provision where secondary access to the Applicable Market Center Point applies on only the Access Segment. DETI asserts that secondary access on the Delivery Segment is not necessary because DETI has the capability to provide primary access on the Delivery Segment. We find these rights are permissible because they do not present a risk of undue discrimination, do not affect the operational conditions of providing service, and do not result in any customer receiving a different quality of service.[199]

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[196] Where a Customer's Primary Receipt Point entitlement is designated as upstream of Valley Gate Junction, the Applicable Market Center Point is South Point. *See* GT&C Section 11A.4.G of DETI's Tariff.

[197] The Access Segment is from the Customer's Receipt Point to the Applicable Market Center Point. *See* GT&C Section 11A.4.G of DETI's Tariff.

[198] The Delivery Segment is from the Applicable Market Center Point to the Customer's Delivery Point. *See* GT&C Section 11A.4.G of DETI's Tariff.

[199] Exhibit A to the FTS Agreement provides in relevant part that "[f]or purposes of Section 11.A.4.G [of DETI's GT&C] … access to the Applicable Market Center Point for the Access Segment (as those terms are defined in [DETI's GT&C] for all Points of Receipt shall be South Point on a Secondary basis only." However, it appears that the referenced section is stated erroneously, missing a parenthetical placement. DETI is directed to correct the parenthetical placement, and identify all non-conforming

F. **Atlantic's *Pro Forma* Tariff**

1. **North American Energy Standards Board (NAESB)**

136. Atlantic states that it intends to include tariff provisions in GT&C section 12, Nomination and Confirmation, and GT&C section 17, Incorporation of NAESB Standards, implementing the NAESB Wholesale Gas Quadrant's (WGQ) revised business practice standards that the Commission incorporated by reference in its regulations. Atlantic is directed to file tariff records, 30 to 60 days prior to its in-service date, implementing the latest version of the business practice standards adopted by the NAESB WGQ applicable to interstate natural gas pipelines.[200]

2. **GT&C Section 5 – Billing and Payments**

137. GT&C section 5.5 of Atlantic's tariff outlines the procedure for handling a customer's failure to make a full payment of any portion of any bill for services received. Specifically, GT&C section 5.5.B states, in part, "[i]f after 15 days Customer has not yet paid Pipeline or has not provided written assurances as required by GT&C Section 6.5, then Pipeline shall be authorized to suspend service."

138. The Commission has not permitted pipelines to impose reservation charges when a pipeline elects to suspend service and it is not providing the service required under the contract during suspension. Thus, Commission policy for suspension of service provides that when pipelines elect to suspend service they are making an election of remedies; i.e., they are determining that the risks of continued service outweigh the potential collection of reservation or other charges during the time of the suspension.[201]

139. We approve the above-quoted language in GT&C section 5.5.B of Atlantic's tariff subject to revision because it does not make clear that Atlantic may not impose reservation charges during any such period of suspension. Therefore, we direct Atlantic to include additional language specifying that Atlantic will not impose reservation

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provisions in redline format in section C3 of Exhibit A to the FTS Agreement, as appropriate.

[200] The NAESB WGQ Version 3.0 Standards were promulgated in *Standards for Business Practices of Interstate Natural Gas Pipelines; Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities*, Order No. 587-W, FERC Stats. & Regs. ¶ 31,373 (2015), *order on reh'g*, 154 FERC ¶ 61,207 (2016).

[201] *Policy Statement on Creditworthiness for Interstate Natural Gas Pipelines and Order Withdrawing Rulemaking Proceeding*, 111 FERC ¶ 61,412, at P 24 (2005).

charges during the period of suspension, consistent with the Commission's policy noted above.

3. GT&C Section 9 – Force Majeure

140. Atlantic's proposed definition of force majeure events in GT&C section 9.2 includes "arrests and priority limitation or restraining orders of any kind of the government of the United States or a State or of any civil or military entity." The Commission has found that outages necessitated by compliance with government standards concerning the regular, periodic maintenance activities a pipeline must perform in the ordinary course of business to ensure the safe operation of the pipeline, including the Pipeline and Hazardous Materials Safety Administration's integrity management regulations, are non-force majeure events requiring full reservation charge credits.[202] Conversely, outages resulting from one-time, non-recurring government requirements, including special, one-time testing requirements after a pipeline failure, are force majeure events requiring only partial crediting.[203] Atlantic's proposed tariff language conflicts with these Commission policies because it can be interpreted to include regular, periodic maintenance activities required to comply with government actions as force majeure events.

141. In addition, Atlantic's proposed definition of force majeure events in GT&C section 9.2 includes "any other causes, whether of the kind herein enumerated or otherwise, *not reasonably within the control* of the party claiming suspension, which by due diligence such party is unable to overcome."[204] The Commission has defined force majeure outages as events that are both "unexpected and uncontrollable."[205] Therefore, we direct Atlantic to revise GT&C section 9 to comply with the Commission Policies, as described above.

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[202] *Kinder Morgan Louisiana Pipeline LLC*, 154 FERC ¶ 61,145, at P 30 (2016); *TransColorado Gas Transmission Co., LLC* , 144 FERC ¶ 61,175, at PP 35-43 (2013); and *Gulf South Pipeline Co., LP*, 141 FERC ¶ 61,224, at PP 28-47 (2012), *order on reh'g*, 144 FERC ¶ 61,215, at PP 31-34 (2013).

[203] *See Algonquin Gas Transmission, LLC*, 153 FERC ¶ 61,038, at P 104 (2015).

[204] Emphasis Added.

[205] *North Baja Pipeline, LLC v. FERC*, 483 F.3d 819, 823 (D.C. Cir. 2007), *aff'g*, *North Baja Pipeline, LLC*, 109 FERC ¶ 61,159 (2004), *order on reh'g*, 111 FERC ¶ 61,101 (2005). *See* also, *e.g.*, *Kinder Morgan Louisiana Pipeline LLC,* 154 FERC ¶ 61,145 at P 29; *Algonquin Gas Transmission, LLC*, 153 FERC ¶ 61,038 at P 103.

4. GT&C Section 10 – Curtailment and Interruption

142. Atlantic's GT&C section 10.2 outlines when and how reductions of service due to curtailments and interruption will be handled and how those reductions of service will be performed. GT&C section 10.2.A outlines the order in which service interruptions, based on scheduled nominations, shall occur. Specifically, section 10.2.A states:

> In cases where Pipeline's ability to Receive, transport, or Deliver is affected, Pipeline shall first order interruption or, where sufficient transportation supplies are available, allocation of transportation quantities to customers based upon scheduled nominations, in the following order:
>
> 1. Scheduled service pursuant to GT&C Section 13.3.G
> 2. Scheduled service pursuant to GT&C Section 13.3.F
> 3. Schedule service under all Firm Transportation Service Agreements pursuant to GT&C Sections 13.3.A through E

GT&C Section 13.3 outlines the order in which customer's nominations will be scheduled, through each point of receipt and delivery, after accounting for any adjustments to a customer's nominations based upon service priorities on segments.

143. The NCUC states that Atlantic's reduction of service provisions in GT&C section 10.2.A.3 appear to apply the same reduction of service priority between primary point and secondary point services. The NCUC suggests that Atlantic's tariff should conform to Commission policy in Order Nos. 636 and 636-A.[206] In Order No. 636-A, the Commission found that existing shippers retained their primary priorities "at designated receipt and delivery points and may not be bumped, preempted, or curtailed under the

[206] NCUC Protest at 11.

flexible receipt and delivery point policy."[207] Order No. 636 and Order No. 636-A also recognized that alternate/flexible points are inferior to primary firm points.[208]

144. In its answer, Atlantic states that the NCUC misinterprets its provision in GT&C section 10.2.A.3 and clarifies that the section was intended to reflect a similar ordering of priorities among firm services when allocating capacity as outlined in GT&C sections 13.3.A through E. Atlantic explains that section 13.3 provides the ordering of nomination priorities, starting with primary point services. Atlantic suggests that to clarify its provision in section 10.2.A.3, it proposes to add the phrase, "in the reverse order of priority provided in that section for scheduling."[209]

145. Atlantic's proposed revision to GT&C section 10.2.A.3 of its tariff, as discussed above, provides that reductions in service will be in the reverse order of the scheduling priorities outlined in GT&C section 13.3. Generally, the scheduling priorities for firm service are based on whether a customer's nomination is at primary points, secondary points within the capacity path, or at secondary points outside the capacity path. We find this approach to be inconsistent with our policy that once scheduled, all firm service is assigned the same priority for curtailment purposes, irrespective of whether capacity is utilized on a primary or secondary basis.[210] Accordingly, we direct Atlantic to revise its tariff to be consistent with Commission policy.

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[207] *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation; and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, Order No. 636, FERC Stats. & Regs. ¶ 30,939, *order on reh'g*, Order No. 636-A, FERC Stats. & Regs. ¶ 30,950, at 30,583, *order on reh'g*, Order No. 636-B, 61 FERC ¶ 61,272 (1992), *order on reh'g*, 62 FERC ¶ 61,007 (1993), *aff'd in part and remanded in part sub nom. United Distribution Cos. v. FERC*, 88 F.3d 1105 (D.C. Cir. 1996), *order on remand*, Order No. 636-C, 78 FERC ¶ 61,186 (1997).

[208] Order No. 636, FERC Stats. & Regs. ¶ 30,939 at 30,429; Order 636-A, FERC Stats. & Regs. ¶ 30,950 at 30,583.

[209] Atlantic Answer at 29.

[210] *Regulation of Short-Term Natural Gas Transportation Services and Regulation of Interstate Natural Gas Transportation Services*, Order No. 637, FERC Stats. & Regs. ¶ 31,091, *clarified*, Order No. 637-A, FERC Stats. & Regs. ¶ 31,099, *reh'g denied*, Order No. 637-B, 92 FERC ¶ 61,062, at 62,013 (2000), *aff'd in part and remanded in part sub nom. Interstate Natural Gas Ass'n of America v. FERC*, 285 F.3d 18 (D.C. Cir. 2002), *order on remand*, 101 FERC ¶ 61,127 (2002), *order on reh'g*, 106 FERC ¶ 61,088 (2004), *aff'd sub nom. American Gas Ass'n v. FERC*, 428 F.3d 255 (D.C. Cir. 2005).

5. **GT&C Section 11 – Requesting and Contracting for Service**

146. GT&C section 11.3 states:

> A Customer request to add a new Primary Point or change an existing Primary Point under a firm Service Agreement may not affect the priority of existing customers using such point as a Primary Point. Pipeline shall be entitled to reasonably reserve point capacity associated with unsold segment capacity. Pipeline shall not be obligated to add a new Primary Point or change an existing Primary Point if such point is associated with unsold segment capacity. A Customer may add or change a Primary Point only if the requested point is within Customer's Capacity Path Entitlements.

147. The NCUC argues that Atlantic's proposed GT&C section 11.3 appears to be inconsistent with the Commission's flexible point policies.[211] The NCUC believes Atlantic is proposing to limit shippers' ability to use capacity outside of their "Capacity Path" entitlements even though shippers pay for capacity on the entire pipeline via postage stamp rates.[212]

148. In its answer, Atlantic states that GT&C section 11.3 is intended to promote Atlantic's ability to market its small amount of unsubscribed capacity. Atlantic asserts that this limited restriction to their flexibility is reasonable and notes that the provision was accepted by all of its customers.[213]

149. In Atlantic's September 20, 2016 data response, Atlantic clarified that GT&C section 11.3 does not limit a customer's ability to nominate to points outside of its capacity path entitlements on a non-permanent basis.[214] Atlantic noted that in Order No. 637-A, the Commission recognized the need to balance the flexible receipt and delivery point policy with a pipeline's interest in marketing unsubscribed capacity, stating "[e]ven if the pipeline is not fully subscribed, it could protect its ability to sell

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[211] 18 C.F.R. §§ 284.221(g) and (h) (2017) (providing pipelines the authority to permit flexible receipt points for receipts of gas volumes into their systems and gives pipelines the authority to permit flexible delivery points for deliveries of gas volumes from their systems).

[212] NCUC Protest at 10.

[213] Atlantic Answer at 29.

[214] Atlantic September 20, 2016 Data Response at 1.

available mainline capacity by reserving an appropriate percentage of the receipt or delivery point capacity to be associated with the unsubscribed mainline capacity."[215]

150. In *Northern Border Pipeline Co.,* the Commission stated that it has required that pipelines permit shippers to move the primary points listed in their contracts to another point that is outside their contractual path on a permanent basis, subject to the availability of capacity.[216] Further, the Commission rejected language proposed by Northern Border similar to the language contained in Atlantic's GT&C section 11.3.[217] Northern Border's tariff language would have permitted it to reserve primary point capacity for the purpose of selling associated unsubscribed capacity. The Commission has found such reservation of point capacity to be unnecessary on a system where the Commission has allowed a pipeline to limit primary point capacity to mainline contract demand.[218] We therefore reject Atlantic's proposal to reserve unsold segment capacity for unsubscribed mainline capacity. Further, Atlantic is directed to clarify its tariff language so that shippers are permitted to permanently change a primary point, subject to available capacity and payment of the appropriate additional incremental rate to cover the cost of additional capacity reserved, as directed in *Northern Border*.

6. GT&C Section 13 – Scheduling and Scheduling Priorities

151. GT&C section 13 outlines the processes and priorities for scheduling a customer's nominated gas on Atlantic's system. As previously discussed, GT&C section 13.3 outlines the order in which an Atlantic customer's point nominations will be scheduled.

152. In GT&C section 13.3.C and 13.3.D, Atlantic proposes to schedule those customers nominating receipts or deliveries within their contract MDTQ at a primary point for the purpose of resolving imbalances under FT service agreements before scheduling those customers nominating firm service at points outside of their capacity path entitlements. The Commission has stated that imbalance quantities for makeup or payback should not be given a higher scheduling priority than any firm service quantities, stating that firm service with secondary scheduling rights is still firm service, and

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[215] *Id.* at 2 (citing Order 637-A, FERC Stats. & Regs. ¶ 31,099 at 31,594 n.121).

[216] *Northern Border Pipeline Co.*, 103 FERC ¶ 61,134, at PP 36-37 (2003) (*Northern Border*).

[217] *Id.*

[218] *Id.* (citing *ANR Pipeline Co.*, 103 FERC ¶ 61,022, at P 44 (2003)).

therefore, should have a scheduling priority directly following primary firm service.[219] Atlantic's proposal in GT&C section 13.3.C and 13.3.D contradict this Commission Policy, as imbalances under 13.3.C would have scheduling priority over firm nominations in 13.3.D. Therefore, Atlantic must revise its scheduling point priorities by moving the scheduling priority of firm primary point imbalances (GT&C section 13.3.C) after the scheduling priority for those customers nominating firm service at points outside of their capacity path entitlements (GT&C section 13.3.D).

7. GT&C Section 25 – Right of First Refusal

153. Atlantic's GT&C section 25 outlines the provisions within a qualifying customer's service agreement that enables it to continue service under a right of first refusal (ROFR) pursuant to its existing rate schedule and service rights. GT&C section 25.2.C provides that a customer may "elect[] to exercise the ROFR as to only a portion of its capacity." GT&C section 25.2.F.4 provides, in part, that "Pipeline shall notify Customer and the winning bidder in writing of the best bid(s), within five business days after the close of the bid period. The notice to Customer shall include an executable copy of a Service Agreement in the Form of Service Agreement set forth in this Tariff and containing the matching terms" and "[i]f a competing bidder or bidders submits a bid for only a portion of Customer's capacity subject to the ROFR, Customer must match that bid to retain the amount of capacity to which the bid applies." In addition, GT&C section 25.2.F.6 provides, in part, that if no competing bidder submits an applicable bid, "Customer may exercise its ROFR for all or a part of the capacity by notifying Pipeline."

154. We find that although GT&C section 25.2 provides that a customer may elect to retain only a portion of its capacity, GT&C section 25.2 does not expressly indicate when, in the ROFR bid matching process, the customer can make such election. The Commission's long-standing policy is that such election is not required until the service provider has notified the existing shipper of the best bid(s) received from third parties for all or a portion of the expiring capacity.[220] Therefore, Atlantic is directed to clarify GT&C section 25.2 to provide that a shipper is not required to elect how much capacity it will seek to retain through the ROFR process until after receiving notification from Atlantic as to the best offer(s) for its expiring capacity, and may then notify Atlantic of its intent to match the best offer(s) for all or a volumetric portion of its capacity.

155. GT&C section 25.F.4 provides, in part:

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[219] *Colorado Interstate Gas Company*, 111 FERC ¶ 61,216, at P 19 (2005); *Panhandle Eastern Pipe Line Company*, 78 FERC ¶ 61,202, at 61,872 (1997).

[220] *See, e.g., Sierrita Gas Pipeline, LLC*, 147 FERC ¶ 61,192, at P 77 (2014); *Transcontinental Gas Pipe Line Corp.*, 101 FERC ¶ 61,267, at P 26 (2002).

> *To retain capacity, Customer must match the competing bids up to the recourse rate applicable to the service currently being provided under the subject Service Agreement, for the term bid by the best bidder.* In determining whether the existing Customer's bid matches the best third party bid, Pipeline shall use the evaluation criteria specified in its posted notice pursuant to GT&C Section 26.2, as applied to the quantity of service that Customer elects to retain.[221]

156. The emphasized language quoted above contradicts the sentence that follows it. Pursuant to GT&C section 26.2, the pipeline will include in its notice the criteria by which the pipeline will evaluate bids. GT&C section 26.4.D.1 provides one of the evaluation criteria as "[t]he highest net present value (NPV) of the reservation charges or other source of guaranteed revenue to be received by Pipeline over the term of service." The Commission has found that "[u]nder an NPV bid evaluation method, shippers may bid whichever combination of rate and term best represents the value they place on the capacity."[222] Thus, an existing shipper is not required to match the rate or term bid by a third party when the pipeline has posted in the notice that NPV will be the bid evaluation criteria. Therefore, we direct Atlantic to delete the emphasized language quoted above from GT&C section 25.F.4.

8. <u>GT&C Section 29 – Off System Capacity</u>

157. Atlantic's proposed section 29.1 provides as follows:

> From time to time, Pipeline may enter into transportation and/or storage agreements with other interstate or intrastate pipeline companies. If Pipeline acquires capacity on an off-system pipeline, Pipeline will only render service to Customers on the acquired capacity pursuant to Pipeline's FERC Gas Tariff and subject to approved and/or negotiated rates, as such tariff and rates may charge from time to time. For transactions entered into under this Section 29, such capacity shall be referred to as "Off System Capacity", and further, the "shipper must have title" requirement is waived.

158. We find that this language is consistent with the Commission's *Texas Eastern* policy concerning the acquisition of upstream capacity by interstate pipelines.[223] Under

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[221] Emphasis Added.

[222] *Transcontinental Gas Pipe Line Corp.,* 105 FERC ¶ 61,365, at P 20 (2003).

[223] *Texas Eastern Transmission Corp.*, 93 FERC ¶ 61,273 (2000), *reh'g denied,* 94 FERC ¶ 61,139 (2001) (*Texas Eastern*).

that policy a pipeline can acquire off-system capacity without preapproval if it makes a tariff filing that includes a statement that it will only transport gas for others on the acquired capacity pursuant to its open access tariff and subject to its Commission-approved rates. Upon the pipeline filing an appropriate tariff provision, we will grant a generic waiver of the "shipper must hold title" policy for any such transportation that the pipeline subsequently provides.

159. Atlantic states that it will utilize capacity on the DETI Supply Header Project to serve its customers in a seamless, integrated fashion, treating natural gas received through the DETI Supply Header Project as if it is a receipt onto its own system.[224] Atlantic's GT&C section 29.2 outlines the terms and conditions for its primary firm transportation customers that have rights on DETI as outlined in their service agreements. Atlantic states that all of its customers desired the option to have access to DETI capacity corresponding to their full MDTQs.[225]

160. The NCUC filed comments suggesting that the language contained in GT&C section 29.1 appears to be inconsistent with the discussion regarding Atlantic's DETI capacity in its transmittal letter. Specifically, the NCUC states that Atlantic indicated in its application that a shipper on its system may use any point on the DETI system on a secondary basis "in accordance with the terms of D[E]TI's FERC Gas Tariff" while GT&C section 29.1 states in part that the "Pipeline will only render service to Customers on the acquired capacity pursuant to Pipeline's FERC Gas Tariff."[226]

161. In its answer, Atlantic states that in addition to GT&C section 29.1, section 29.2 provides that customer's "rights shall not exceed the rights of Pipeline under its firm transportation service agreement with D[E]TI or D[E]TI's FERC Gas Tariff." Atlantic explains that the statement in its initial application was a short-hand reference to its tariff provision and that the tariff provision should resolve any perceived inconsistencies.[227]

162. GT&C section 29.2.D states that "[c]ustomer may utilize any points of receipt or delivery on the D[E]TI system, provided however, Customer's rights shall not exceed the rights of Pipeline under its firm transportation service agreement with D[E]TI or D[E]TI's FERC Gas Tariff … ." We find the language contained in GT&C section 29 to be acceptable.

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[224] Atlantic Initial Application at 19.

[225] *Id.*

[226] NCUC Protest at 11.

[227] Atlantic Answer at 30.

9. **GT&C Section 37 – Overruns and Penalties**

163. GT&C section 37 of Atlantic's tariff outlines the provisions for overruns and penalties for both authorized and unauthorized overruns applicable to each shipper's MDTQ.

164. The NCUC states that the penalties contained in GT&C section 37 are cumulative and that the Commission has held that pipelines are prohibited from applying multiple penalties for the same infraction.[228] The NCUC further states that section 37 appears to contradict the alternative point rights set out in Rate Schedule FT section 5.3 and is inconsistent with the Commission's flexible point policies as it assesses an overrun penalty if a shipper uses its capacity at an alternative point and exceeds its Maximum Daily Receipt Obligation (MDRO) or Maximum Daily Delivery Obligation (MDDO) at that point even if the shipper is within its overall daily contract quantity. The NCUC also argues that GT&C section 37.4 provides no basis for charging shippers for Operational Balancing Agreement (OBA) costs if shippers are in perfect balance every day within a given month.[229]

165. Atlantic, in its answer, states that a shipper would not incur multiple penalties on any single dekatherm delivered; rather, a shipper could incur different penalties on different quantities within the same day. Atlantic further explains that a shipper could incur scheduling penalties, as outlined in GT&C section 37.3, for certain quantities and then incur overrun penalties, as outlined in GT&C section 37.2, for different quantities within the same day. For example, Atlantic states that "[if] a shipper schedules 80% of its MDTQ and then takes 105% of its MDTQ: that shipper would incur scheduling penalties for quantities between 80% and 102% of the MDTQ and overrun penalties on the quantities in excess of 102%."[230] Atlantic concludes that a shipper could not incur multiple penalties on any single dekatherm delivered, but in its example, would incur two different penalties on the different quantities on the same day. Atlantic also notes that penalties associated with Operational Flow Orders, as provided in GT&C section 18.5.C, are in lieu of any penalties assessed pursuant to sections 37.2 and 37.3. Atlantic concludes that its terms and conditions for assessing penalties are reasonable and consistent with Commission policy.[231]

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[228] NCUC Protest at 11.

[229] *Id.* at 12.

[230] Atlantic Answer at 30.

[231] *Id.*

166. In response to the NCUC's concerns regarding alternative point rights and overrun penalties, Atlantic states that the NCUC misconstrues the provision in GT&C section 37.2. Atlantic states that shippers only have applicable MDDOs and MDROs at the primary points along their contract paths; therefore, a shipper could not exceed a maximum contractual point right and incur an overrun charge when delivering or receiving gas at an alternative point.[232]

167. Lastly, in response to the NCUC's concern that a shipper would be assessed OBA costs even if they were in perfect balance every day of the month, Atlantic suggests the NCUC overlooked a relevant portion of the language contained in GT&C section 37.4, emphasized below:[233]

> Customer shall be responsible for any charges that are incurred by Pipeline pursuant to the operational balancing agreements (OBA) between Pipeline and the upstream and downstream interconnecting pipelines to the extent such charges are not recovered or offset through any other sources. Upon determination that certain OBA charges are not recoverable from such sources and *to the extent such charge incurred by Pipeline is caused by Customer(s)*, Pipeline shall promptly bill such Customers(s) in the next billing invoice for such charges pro rata based on the Customers' scheduled quantities for the applicable month. Upon request of the Customer, Pipeline shall provide documentation in support of any charges billed pursuant to this Section.

168. We find that Atlantic's proposed overrun and penalty provisions are in compliance with Order No. 637, relying on penalties when necessary to protect system integrity.[234] Commission policy prohibits multiple penalties for the same infraction.[235] Atlantic has satisfactorily clarified the concerns raised by the NCUC; therefore, we find the language contained in GT&C section 37 acceptable and consistent with Commission precedent and policy, as discussed further below.

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[232] *Id.* at 28.

[233] *Id.* at 31.

[234] *See* Order No. 637-A, FERC Stats. & Regs. ¶ 31,099 at 31,598.

[235] *Crossroads Pipeline Co.*, 71 FERC ¶ 61,076, at 61,265 (1995) and 100 FERC ¶ 61,025, at P 51 (2002); *East Tennessee Natural Gas Co.*, 98 FERC ¶ 61,060, at P 107 (2002); *Columbia Gas Transmission Corp.*, 100 FERC ¶ 61,084, at P 201 (2002).

169. Atlantic's GT&C section 37.5 provides for the crediting of unauthorized overrun and penalty revenues to its customers. GT&C sections 30.2 and 30.3 outline Atlantic's ability to confiscate unauthorized gas volumes; however, section 37.5 does not provide for a mechanism to credit such confiscated gas volumes to existing customers. The Commission has found that a pipeline's confiscation of gas left on its system is an operationally justified deterrent to shipper behavior that could threaten the system or degrade service to firm shippers.[236] However, the Commission has found that the value of such confiscated gas must be credited to existing customers. Atlantic has not provided such a mechanism in its tariff. Therefore, we direct Atlantic to revise section 37.5 of its tariff to credit the value of any confiscated gas, net of costs, to non-offending shippers.

10. GT&C Section 37.3 – Scheduling Penalty

170. GT&C Section 37.3 of Atlantic's initial application provides as follows:

> If Deliveries by a Customer to a Point of Delivery on any Gas Day deviate from the scheduled quantity by more than 5%, then Customer shall be subject to a scheduling penalty. The scheduling penalty shall equal the rate published on Tariff Record No. 10.30 for each Dt of deficiency below 95% of scheduled quantities and each Dt of excess above 105% of scheduled quantities. Customer shall pay the Scheduling Penalty in addition to any other applicable charges and penalties. However, for purposes of determining the Scheduling Penalty applicable to Customer, any available Section 41 Pack Account Balance shall be used to reduce the deficiency, and any available Customer's Section 41 MPQ. shall be used to reduce the excess before a Scheduling Penalty is calculated.

171. On October 23, 2015, Atlantic filed to modify section 37.3 of its tariff to include the following sentence at the end of the proposed language in section 37.3: "For firm customers that do not hold a Section 41 Pack Account, the 5% threshold shall be based on 5% of Customer's MDTQ in lieu of scheduled quantities." Atlantic believes this additional language will provide an adequate incentive for its customers to schedule accurately without impacting the service of other customers on its system.

172. As discussed above, we find that the special no-notice service via a "pack account" is not a permissible material deviation and directed Atlantic to remove the provision from the non-conforming service agreement. Therefore, we reject Atlantic's modified section 37.3, as it relates to firm customers that do not hold a "pack account."

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[236] *AES Sparrows Point LNG, LLC*, 126 FERC ¶ 61,019, at P 42 (2009); *Colorado Interstate Gas Co.*, 122 FERC ¶ 61,256, at P 102 (2008).

173. The Commission has found with regard to the tolerance level for daily scheduling penalties during non-critical periods, that pipelines must have penalty provisions in place which are at a sufficient level to prevent impairment of reliable service.[237] Determining the penalty tolerance levels necessary to deter certain conduct is an exercise of reasonable judgment.[238] Therefore, when Atlantic submits its proposed tariff 30 to 60 days prior to its in-service date, Atlantic may submit the GT&C section 37.3[239] as proposed in its initial application[240] or the modified GT&C section 37.3. However, whichever language Atlantic chooses must afford all shippers the same rights.

11. GT&C Section 38 – Interruptible Services Revenue Crediting

174. The Commission's policy regarding new interruptible services requires the pipeline either to credit 100 percent of the interruptible revenues, net of variable costs, to maximum rate firm and interruptible customers, or to allocate costs and volumes to these services.[241] Atlantic chose the interruptible revenue crediting option.

175. Atlantic proposes to credit 100 percent of its interruptible revenue credits accrued during the calendar year to customers paying recourse rates or negotiated reservation rates under long-term contracts of one year or more and to interruptible customers and short-term customers pursuant to GT&C section 38.3 of its *pro forma* tariff. Atlantic states that the revenue credits will be allocated based on each respective customer's actual base reservation revenue contribution as a percentage of the total base reservation contribution of all eligible customers during the annual revenue crediting period.

176. Atlantic's GT&C section 38.3 states that shippers eligible for interruptible revenue credits may include negotiated rate shippers. We agree that Atlantic is permitted to share

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[237] *MoGas Pipeline LLC,* 151 FERC ¶ 61,201, at P 10 (2015).

[238] *Id.*

[239] As discussed below, Atlantic is directed to remove all references of the "pack account" from its tariff and *pro forma* service agreements.

[240] As proposed in Atlantic's initial application, GT&C section 37.3 is consistent with Commission Policy. *Columbia Gas Transmission Corp.*, 133 FERC ¶ 61,217, at P 56 (2010)

[241] *See, e.g., Creole Trail LNG, L.P.*, 115 FERC ¶ 61,331, at P 27 (2006); *Entrega Gas Pipeline Inc.*, 112 FERC ¶ 61,177, at P 51 (2005).

interruptible revenues with its negotiated rate shippers;[242] however, we note that maximum rate customers, as a group, must receive a proportionate share of 100 percent of interruptible revenues collected (less administrative costs to provide the interruptible service).[243] Interruptible revenues due to maximum rate shippers cannot be reduced to reflect revenues for negotiated rate agreements. Further, the provisions of a negotiated rate are specific to actual negotiated rate filings and are required to be reported in a tariff record that identifies the negotiated rate provisions.[244] However, in general, the Commission has found that it is not appropriate to place language on negotiated rate terms in various sections of the GT&C of the tariff. Therefore, we accept the provisions in section 38 subject to Atlantic to removing references to negotiated rates in this section.[245]

177. The NCUC states that GT&C section 38.4 provides that Atlantic will only pay interest on overrun funds collected from January through March when a revenue credit is to be provided, however, no interest will be paid for the period during the year in which the credit is accruing.[246] In Atlantic's August 19, 2016 data response, Atlantic clarified language contained in GT&C section 38.4, which intended to state that Atlantic will accrue interest on revenue credits from interruptible transportation service rendered from January 1 to December 31 of any given year and continuing through the month prior to when the customer will be invoiced. In the August 19, 2016 data response, Atlantic also proposes to revise GT&C section 38.4 to state "[r]evenue credits shall be paid to Customers via a credit on the invoices sent to Customers *in April*…" in order to clarify when customer invoices will be sent. Atlantic proposes an additional clarification to section 38.4, which states "pipeline shall accrue interest through March of the year in which Customer invoices are credited."[247] Atlantic proposes to make the modifications to GT&C section 38.4 when actual tariff records are submitted 30 to 60 days prior to the in-

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[242] *Cheyenne Plains Gas Pipeline Co., L.L.C.*, 108 FERC ¶ 61,052, at PP 12-13 (2004); *Wyoming Interstate Co. Ltd.*, 121 FERC ¶ 61,135, at P 11 (2007).

[243] *Wyoming Interstate Co. Ltd.*, 121 FERC ¶ 61,135, at P 11 (2007).

[244] Alternative Rate Policy Statement, 74 FERC ¶ 61,076, *order granting clarification*, 74 FERC ¶ 61,194, *order on reh'g and clarification*, 75 FERC ¶ 61,024, *reh'g denied*, 75 FERC ¶ 61,066, *reh'g dismissed*, 75 FERC ¶ 61,291 (1996), *petition denied sub nom. Burlington Res. Oil & Gas Co. v. FERC*, 172 F.3d 918 (D.C. Cir. 1998).

[245] *Florida Southeast Connection, LLC*, 154 FERC ¶ 61,080 at P 131.

[246] NCUC Protest at P 12.

[247] Atlantic August 19, 2016 Data Response at Question No. 4.

service date. Atlantic's proposed modifications to GT&C section 38.4 of its tariff satisfactorily clarify the confusion surrounding the interest to be paid to customers, as raised by the NCUC.

12. GT&C Section 39 – Reservation Charge Adjustment

178. GT&C section 39.2.A states that "Pipeline shall not be obligated to provide reservation charge credits on any Day for quantities not delivered to Customer under the following circumstances … [d]ue to the conduct of the upstream point operator at the firm Primary Receipt Point or the downstream point operator of the facilities at the firm Primary Delivery point, not controlled by the Pipeline … ." The NCUC suggests that it is not clear whether DETI, an affiliate and upstream operator, potentially having the inability to supply gas to Atlantic should be considered a force majeure event on Atlantic's system after 10 days.[248]

179. In its response, Atlantic states that its tariff exception to not provide reservation charge credits to its customers in the event deliveries are interrupted due to an upstream or downstream operator, as provided in section 39.2.A.3, is fully consistent with Commission policy. Atlantic states that the exception is applicable because it does not control the actions of its interconnecting point operator, and the fact that an affiliate happens to be the upstream interconnecting pipeline is immaterial.[249]

180. The Commission permits pipelines to include tariff exemptions from providing reservation charge credits in situations such as those proposed by Atlantic in section 39.2.A.3.[250] Further, the Commission has required pipelines to clarify that such exemptions are only applicable when the pipeline's failure to perform is caused solely by the conduct of others not controllable by the pipeline (i.e., operating conditions on upstream or downstream facilities).[251] As Atlantic notes, whether the upstream or downstream interconnecting pipeline is affiliated is irrelevant. Therefore, we will accept the proposed tariff language.

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[248] NCUC Protest at 12.

[249] Atlantic Answer at 31-32.

[250] *See, e.g. Enable Gas Transmission, LLC*, 152 FERC ¶ 61,052, at PP 133-134 (2015); *Dominion Transmission, Inc.*, 142 FERC ¶ 61,154, at PP 51-52 (2013).

[251] *See, e.g., Gulf South Pipeline Co., LP*, 141 FERC ¶ 61,224 at P 84; *Iroquois Gas Transmission Sys., L.P.*, 145 FERC ¶ 61,233, at PP 43-44 (2013); *Gas Transmission Northwest LLC*, 141 FERC ¶ 61,101, at P 42 (2012); *Paiute Pipeline Co.*, 139 FERC ¶ 61,089, at P 31 (2012).

13. **GT&C Section 41 – Foundation/Anchor Shipper Pack Account**

181. GT&C section 41 provides Foundation and Anchor shippers a no-notice service via a "pack account." As discussed above, we rejected Atlantic's proposed no-notice service as unduly discriminatory. Therefore, Atlantic is required to remove section 41, including all references to such section within the tariff and *pro forma* service agreements.

14. **GT&C Section 42– Imbalance Resolution Procedures**

182. GT&C section 42 of Atlantic's tariff outlines the procedures for resolving system imbalances and requires that each customer eliminate its end-of-month imbalances under each transportation service agreement per the timeline of this section. GT&C section 42.5 states that "[a] customer may correct such net imbalance within seventeen (17) business days after Customer receives such notification of the month-end imbalance from Pipeline."

183. The NCUC states that GT&C section 42.5 provides that if a shipper does not correct its net imbalance within 17 business days after it receives notice of its month-end imbalance, Atlantic has the right to correct the imbalance by immediately suspending deliveries to or receipts from the shipper. The NCUC suggests that this type of discretion appears to be "draconian" because it could be applied to imbalances of any size without regard to whether there is an adverse system impact.[252]

184. In its answer, Atlantic states shippers have multiple opportunities and ways to correct their imbalance over the 17-day time period in accordance with Atlantic's tariff and the applicable NAESB rules. Atlantic further suggests that the need for the right to take decisive action for imbalances that remain uncorrected after the 17-day period arises from Atlantic's lack of storage, limited line pack, and no cash-out provisions for imbalances. Atlantic suggests its tariff language and actions taken in such circumstances are reasonable.

185. The Commission's regulations provide that a pipeline with imbalance penalty provisions in its tariff must provide, to the extent operationally practicable, parking and lending or other services that facilitate the ability of shippers to manage transportation imbalances, as well as the opportunity to obtain similar imbalance management services from other providers without undue discrimination or preference.[253] In Order No. 637, the Commission stated that "pipelines will be required to provide imbalance management

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[252] NCUC Protest at 13.

[253] 18 C.F.R. § 284.12(b)(2)(iii) (2017).

services, like park-and-loan service, and greater information about the imbalance status of shippers and the system, to make it easier for shippers to remain in balance in the first instance."[254] In *Gulf Crossing*, the Commission stated in limited circumstances, where the pipeline lacked storage facilities that can be used for imbalance management and where the pipeline had limited ability to use line pack for such purposes, the Commission has not required the pipeline to provide park and loan services.[255] The Commission has historically urged pipelines to establish services, such as park and loan services, and to propose that they be implemented whenever they are operationally feasible, to reduce reliance on penalties to resolve imbalances.[256]

186. Atlantic has provided two justifications for not offering a park and loan service on its system: (1) a lack of storage on its system and (2) a limited capability to use line pack. Because we have denied Atlantic's no-notice service for Foundation and Anchor shippers, it is not clear that Atlantic is unable to offer a park and loan service on its system. Therefore, we direct Atlantic to either file to implement park and loan services or to fully explain and document why it is operationally infeasible to do so.

G. Accounting

187. For the period March 2015 through August 2016, Atlantic's proposed Allowance for Funds Used During Construction (AFUDC) rate is in excess of its proposed overall rate of return underlying its recourse rates, resulting in an over accrual of AFUDC.[257] AFUDC is a component part of the cost of constructing a project. Gas Plant Instruction 3(17) prescribes a formula for determining the maximum amount of AFUDC that may be capitalized as a component of construction cost.[258] That formula, however, uses prior-year book balances and actual costs of borrowed and other capital. In cases of newly created entities, such as Atlantic, prior-year book balances do not exist; therefore, using the formula contained in Gas Plant Instruction 3(17) is not feasible for initial construction projects. Thus, to ensure that appropriate amounts of AFUDC are capitalized for this

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[254] Order No. 637, FERC Stats. & Regs. ¶ 31,091 at 31,309.

[255] *Gulf Crossing Pipeline Company LLC*, 124 FERC ¶ 61,282, at P 7 (2008) (*Gulf Crossing*).

[256] *See, e.g., High Island Offshore System, L.L.C.*, 97 FERC ¶ 61,156, at 61,690 (2001).

[257] To calculate its AFUDC rate of 14 percent, Atlantic used a 100 percent equity for the period March 2015 through August 2016.

[258] 18 C.F.R. pt. 201 (2017).

project, we will require Atlantic to capitalize the actual costs of borrowed and other funds for construction purposes, not to exceed the amount of debt and equity AFUDC that would be capitalized based on the overall rate of return underlying its recourse rates.[259]

188. In similar cases, the Commission has limited the maximum amount of AFUDC that the pipeline could capitalize by limiting the AFUDC rate to a rate no higher than the overall rate of return underlying its recourse rates (i.e., the rate that it could earn on operating assets).[260] Consistent with this precedent, we will therefore require Atlantic to revise its AFUDC methodology to ensure that its maximum AFUDC rate for the entire construction period is no higher than the overall rate of return underlying its approved recourse rates. Further, Atlantic must use its actual cost of debt (short-term and long-term) in the determination of its AFUDC rate, if it results in an AFUDC rate lower than the overall rate of return underlying its recourse rates.[261]

189. Last, Atlantic proposes to lease up to 100,000 Dth/d of available capacity on Piedmont's system. We will require Atlantic to treat the capacity lease with Piedmont[262] as an operating lease and record the monthly lease payments in Account 858, Transmission and Compression of Gas by Others, consistent with similar capacity lease agreements approved by the Commission.[263]

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[259] *See, e.g.*, *Creole Trail LNG L.P.*, 115 FERC ¶ 61,331; *Port Arthur LNG, L.P.*, 115 FERC ¶ 61,344 (2006); *Golden Pass LNG Terminal LP*, 112 FERC ¶ 61,041 (2005).

[260] *See Gulfstream Natural Gas System, L.L.C.*, 91 FERC ¶ 61,119 (2000); *Buccaneer Gas Pipeline Company L.L.C.*, 91 FERC ¶ 61,117 (2000).

[261] *See Weaver Cove Energy, LLC*, 112 FERC ¶ 61,070 (2005); *Pacific Connector Gas Pipeline, LP*, 129 FERC ¶ 61,234 (2009).

[262] Piedmont seeks only a limited-jurisdiction certificate under section 7(c) of the NGA authorizing it to make the leased capacity available for transportation of natural gas in interstate commerce; as such, Piedmont is not required to submit proposed accounting entries recording the capacity lease receipts from Atlantic.

[263] *See, e.g.*, *Midwestern Gas Transmission Company*, 73 FERC ¶ 61,320 (1995); *TriState Pipeline LLC*, 88 FERC ¶ 61,328 (1999); *Gulf Crossing Pipeline Company LLC*, 123 FERC ¶ 61,100 (2008); *Columbia Gas Transmission, LLC*, 145 FERC ¶ 61,028 (2013); and *Constitution Pipeline Co.*, 149 FERC ¶ 61,199.

H. Environmental Analysis

1. Pre-filing Review

190. On November 13, 2014, Commission staff granted Atlantic's and DETI's requests to use the pre-filing environmental review process in Docket Nos. PF15-6-000 and PF15-5-000, respectively. As part of the pre-filing review, on February 27, 2015, the Commission issued a *Notice of Intent to Prepare an Environmental Impact Statement for the Planned Supply Header Project and Atlantic Coast Pipeline Project, Request for Comments on Environmental Issues, and Notice of Public Scoping Meetings* (NOI). The NOI was published in the *Federal Register* on March 6, 2015,[264] and mailed to 6,613 entities, including federal, state, and local government representatives and agencies; elected officials; environmental and public interest groups; Indian Tribes and Native Americans; potentially affected landowners; other interested individuals and entities; and local libraries and newspapers. The NOI briefly described the projects and the Commission's environmental review process, provided a preliminary list of issues identified by Commission staff, invited written comments on the environmental issues that should be addressed in the draft environmental impact statement (EIS), listed the date and location of 10 public scoping meetings[265] to be held in the project area, and established April 28, 2015, as the deadline for comments. A total of 330 people presented oral comments at the pre-filing public scoping meetings.[266]

191. On August 5, 2015, the Commission issued a *Supplemental Notice of Intent to Prepare an Environmental Impact Statement for the Planned Atlantic Coast Pipeline Project, and Request for Comments on Environmental Issues Related to New Alternatives Under Consideration* that described three route alternatives for the ACP Project in Virginia. The supplemental NOI was published in the Federal Register on August 11, 2015,[267] and sent to 618 entities, including federal, state, and local agencies; elected officials; environmental and public interest groups; Indian Tribes and Native Americans; potentially affected landowners; local libraries and newspapers; and other stakeholders

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[264] 80 Fed. Reg. 12,163 (2015).

[265] Commission staff held the public scoping meetings between March 10 and 24, 2015, in Fayetteville, Wilson, and Roanoke Rapids, North Carolina; Chesapeake, Dinwiddie, Farmville, Lovingston, and Stuarts Draft, Virginia; and Elkins and Bridgeport, West Virginia.

[266] Transcripts of the scoping meetings were placed into the Commission's public record for this proceeding.

[267] 80 Fed. Reg. 48,093 (2015).

who had indicated an interest in the area of the potential alternatives. Issuance of the supplemental NOI opened a 30-day formal supplemental scoping period for filing written comments on the alternatives under consideration.

192. In total, we received approximately 5,600 written comment letters[268] during the pre-filing process, formal scoping and supplemental scoping periods, and throughout preparation of the draft EIS.[269]

2. Application Review

193. As stated above, on September 18, 2015, Atlantic and DETI filed formal applications with the Commission in Docket Nos. CP15-554-000 and CP15-555-000 for the ACP Project and Supply Header Project, respectively. On the same day, Atlantic and Piedmont also filed a joint application in Docket No. CP15-556-000 for the Capacity Lease.

194. On March 14, 2016, Atlantic filed an amendment to its initial application with the Commission in Docket No. CP15-554-001. Atlantic's amended application identified various route modifications to its initially proposed route in West Virginia, Virginia, and North Carolina. As a result, on May 3, 2016, the Commission issued a *Supplemental Notice of Intent to Prepare an Environmental Impact Statement and Proposed Land and Resource Plan Amendment(s) for the Proposed Atlantic Coast Pipeline, Request for Comments on Environmental Issues Related to New Route and Facility Modifications, and Notice of Public Scoping Meetings* that described the route modifications identified in Atlantic's amended application and announced two additional public scoping sessions in Marlinton, West Virginia, and Hot Springs, Virginia, on May 20 and 21, 2016. The second supplemental NOI was published in the Federal Register on May 9, 2016,[270] and sent to 9,694 entities, including federal, state, and local agencies; elected officials; environmental and public interest groups; Indian Tribes and Native Americans; potentially affected landowners; local libraries and newspapers; and other stakeholders who had indicated an interest in the area of the proposed route modifications. Issuance of the second supplemental NOI also opened a 30-day formal scoping and comment period

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[268] Over half the written comment letters were form letters expressing either opposition or support for the projects.

[269] Table 1.3-1 of the final EIS provided a list of environmental issues raised during scoping.

[270] 81 Fed. Reg. 28,060 (2016).

for filing written comments on the alternatives under consideration, which concluded on June 2, 2016. A total of 147 attendees provided oral comments at the meetings.[271]

195. On May 11, 2016, July 6, 2016, and August 29, 2016, Commission staff mailed letters to potentially affected landowners along certain modified and adjusted portions of the ACP Project route in West Virginia and Virginia, and requested comments from the affected landowners.

196. To satisfy the requirements of the National Environmental Policy Act (NEPA),[272] Commission staff evaluated the potential environmental impacts associated with the construction and operation of the ACP Project and Supply Header Project in an EIS. The U.S. Department of Agriculture, Forest Service (Forest Service); U.S. Army Corps of Engineers; U.S. Environmental Protection Agency (EPA); U.S. Fish and Wildlife Service (FWS) West Virginia, Virginia, North Carolina Field Offices and Great Dismal Swamp National Wildlife Refuge; West Virginia Department of Environmental Protection; and the West Virginia Department of Natural Resources participated as cooperating agencies in the preparation of the EIS.

197. Commission staff issued the draft EIS on December 30, 2016, addressing the issues raised during the initial and supplemental scoping periods and up to the point of publication. The *Notice of Availability* for the draft EIS was filed with the EPA and published in the Federal Register,[273] and established a 90-day comment period[274] ending on April 6, 2017. The draft EIS was sent to 9,805 entities on the environmental mailing list for the projects, including additional interested entities that were added since issuance of the NOIs. Commission staff held 10 public sessions between February 13

[271] Transcripts of the public meetings were placed into the Commission's public record for this proceeding.

[272] 42 U.S.C. §§ 4321 *et seq.* (2012). *See also* 18 C.F.R. pt. 380 (2017) (Commission's regulations implementing NEPA).

[273] 82 Fed. Reg. 2,348 (2017).

[274] The Forest Service, as a cooperating agency, is using the Commission's EIS for the purpose of amending the Forest Service Land and Resource Management Plans. Accordingly, the Commission adopted a 90-day comment period for the final EIS to accommodate Forest Service regulations pertaining to public notification and scoping for proposed Forest Service Plan amendments.

and March 2, 2017, in the project areas[275] to take comments on the draft EIS. In total, 620 people provided oral comments at those sessions.[276] Between the issuance of the draft EIS on December 30, 2016, and the end of the comment period on April 6, 2017, the Commission received 1,675 written or electronically filed letters.

198. Commission staff issued the final EIS on July 21, 2017, and the *Notice of Availability* was published in the Federal Register on July 28, 2017.[277] The final EIS addressed timely comments received on the draft EIS.[278] The final EIS was mailed to the same entities as the draft EIS, as well as to newly identified landowners and any additional entities that commented on the draft EIS.[279]

3. Major Environmental Issues and Comments on the Final EIS

199. The final EIS concludes that most environmental impacts resulting from construction and operation of the ACP Project and Supply Header Project would be temporary or short-term, but that some impacts would be adverse and significant.[280] This determination was based on a review of the information provided by Atlantic and DETI in their applications and supplemental filings, including responses to staff data requests; field investigations; scoping; literature research; alternatives analyses; consultations with federal, state, and local agencies, as well as Indian Tribes; and additional information filed by members of the public. As discussed in more detail below, Commission staff considered specified impacts to be short-term to permanent, and forest fragmentation impacts to be significant.[281] Commission staff concludes that constructing the pipelines

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[275] Commission staff held the public comment sessions in Fayetteville, Wilson, and Roanoke Rapids, North Carolina; Suffolk, Farmville, Lovingston, Staunton, and Monterey, Virginia; and Elkins and Marlinton, West Virginia.

[276] Transcripts of the draft EIS comment sessions were placed into the public record for the proceedings.

[277] 82 Fed. Reg. 35,192 (2017).

[278] Appendix Z of the final EIS includes copies of letters in response to the draft EIS received through the close of the comment period, along with Commission staff responses.

[279] The distribution list is provided in Appendix A of the final EIS.

[280] Final EIS at ES-16.

[281] *Id.* at ES-10.

in steep terrain or high landslide incidence areas could increase landslide potential, and, where waterbodies are adjacent to steep terrain, slope instability could have long-term and adverse impacts on water quality and stream channel geometry, and, therefore, downstream aquatic biota.[282] Additionally, constructing the ACP Project facilities could significantly impact cave invertebrates and other subterranean species that occur in only a few known locations, and result in population-level effects on these species.[283] For most other resources, impacts would be reduced to less than significant levels with the implementation of mitigation measures proposed by the applicants and other mitigation measures recommended by Commission staff and included as environmental conditions in the appendix to this order. Major environmental issues of concern addressed in the EIS are discussed below and include: geological resources such as landslides, earthquakes, and karst terrain; water resources, including wells, streams, and wetlands; forested habitat; wildlife and threatened, endangered, and other special status species; land use, recreational areas, and visual resources; socioeconomic issues such as property values, environmental justice, tourism, and housing; cultural resources; air quality; noise; safety; cumulative impacts; and alternatives.

a. Requests to Supplement Draft EIS

200. Several commenters and interveners argue that the draft EIS was insufficient and the Commission should issue a supplemental draft EIS. They assert that, since issuance of the draft EIS, Atlantic and DETI filed extensive, additional information on which commenters should have an opportunity to comment.[284]

201. A purpose of a draft EIS is to elicit suggestions for change.[285] The Council on Environmental Quality (CEQ) regulation that the commenters rely upon calls for a supplemental draft or final EIS if the agency "makes substantial changes in the proposed action that are relevant to environmental concerns" or "there are significant new circumstances or information relevant to environmental concerns."[286] The Supreme Court, in *Marsh v. Oregon Natural Resources Council*, stated that under the "rule of reason," "an agency need not supplement an [EIS] every time new information comes to

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[282] *Id.* at ES-4 and 12.

[283] *Id.* at ES-14.

[284] Commenters cite 40 C.F.R. § 1502.9(c)(1)(ii) (2017).

[285] *See City of Grapevine, Tex. v. DOT*, 17 F.3d 1502, 1507 (D.C. Cir. 1994) ("[t]he very purpose of a [draft EIS] is to elicit suggestions for change.").

[286] 40 C.F.R. § 1502.9(c)(1) (2017).

light after the EIS is finalized."[287] Further, NEPA only requires agencies to employ proper procedures to ensure that environmental consequences are fully evaluated, not that a complete plan be presented at the outset of environmental review.[288] In *National Committee for New River v. FERC*,[289] the court held that "if every aspect of the project were to be finalized before any part of the project could move forward, it would be difficult, if not impossible, to construct the project."[290]

202. As shown in the final EIS, the additional information submitted by the applicants between the issuance of the draft EIS and final EIS did not cause the Commission to make "substantial changes in the proposed action," nor did it present "significant new circumstances or information relevant to environmental concerns." The final EIS analyzed the relevant environmental information and recommended environmental conditions, which we are imposing in this order, that must be satisfied before the applicants may proceed with their projects.

b. Geological Resources

i. Steep Slopes and Landslides

203. About 84 miles of the ACP Project pipeline route and 24 miles of the Supply Header Project pipeline route will cross topography with slopes greater than 20 percent grade.[291] In West Virginia, 73 percent of the AP-1 mainline will cross areas with a high incidence of, and a high susceptibility to, landslides. In Virginia, approximately 28 percent of the AP-1 mainline route will cross similar areas. The entire Supply Header Project pipeline route will also cross these types of areas. Atlantic and DETI have committed to implementing a *Best in Class Steep Slope Management Program* and to use specialized techniques when constructing on steep slopes. Atlantic and DETI will also implement their *Slip Avoidance, Identification, Prevention, and Remediation - Policy and Procedure* to avoid, minimize, and mitigate potential landslide issues in slip prone areas prior to, during, and after construction.

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[287] *Marsh v. Oregon Natural Resources Council*, 490 U.S. 360, 373 (1989).

[288] *See Robertson v. Methow Valley Citizens Council*, 490 U.S. 332, 352 (1989).

[289] *National Committee for the New River v. FERC*, 373 F.3d 1323, 1329 (D.C. Cir. 2004) (*New River*).

[290] *Id.* (citing *East Tennessee Natural Gas Co.*, 102 FERC ¶ 61,225, at 61,659 (2003)).

[291] *See* Final EIS at 4-28.

204. Specifically, as part of the *Steep Slope Management Program*, Atlantic and DETI would implement mitigation measures for susceptible slopes or hillsides depending on the length and inclination of the slope. Some of these measures include: (1) implanting drainage improvement, such as providing subsurface drainage at seep locations through granular fill and outlet pipes, incorporating drainage into trench breakers using granular fill, and/or intercepting groundwater seeps and diverting them from the right-of-way; (2) buttressing slopes with concrete trench breakers; (3) changing slope geometry to make the slope shallower; (4) benching and re-grading with controlled backfill; (5) using alternative backfill; (6) using chemical stabilization of backfill (e.g., cement, lime); (7) implementing Geogrid reinforced slope that consists of benching existing slope, installing subsurface drains, and incorporating Geogrid reinforcement into compacted backfill; and/or (8) using retaining structures.[292] The final EIS concluded that these measures were generally acceptable. However, because the Phase 2 analysis of slopes was still ongoing, the final EIS recommended, and we will require in Environmental Condition 51, that the final outcomes and designs developed as a result of the Phase 2 analysis be filed with the Commission prior to project construction.

ii. **Karst Terrain**

205. Karst features, such as sinkholes and caves, form as a result of the long-term action of groundwater on subsurface soluble carbonate rocks (e.g., limestone and dolostone). These features could present a hazard to the pipeline due to cave or sinkhole collapse. Commenters expressed concerns regarding subsidence and sinkholes affecting the construction and integrity of the pipeline in areas of karst terrain, and regarding potential impacts on and contamination of karst-related groundwater. The ACP Project will cross 71.3 miles of karst terrain in West Virginia and Virginia, specifically between AP-1 mileposts 59 and 154.[293] Desktop and field surveys conducted by Atlantic identified hundreds of sinkholes and depressions within and adjacent to the ACP Project workspaces. Cave systems and sinking streams also cross beneath and adjacent to the pipeline route.

206. Atlantic and DETI developed a *Karst Mitigation Plan* to minimize and respond to karst activity during construction and operation of the proposed facilities. In addition to the plan, we are requiring further measures to identify and minimize impacts on karst features. Environmental Condition 26 in the appendix to this order requires Atlantic to

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[292] *Id.* at 4-29.

[293] *Id.* at 4-8.

utilize subsurface analysis, LiDAR data,[294] and existing dye tracing studies[295] to further identify and characterize karst features along the project route. Environmental Conditions 28, 29, and 62 through 64 require Atlantic to complete further studies and to minimize impacts on site-specific karst features. Environmental Condition 29 requires Atlantic to revise its *Karst Mitigation Plan* to include post-construction monitoring using LiDAR data. We concur with the Virginia Department of Conservation and Recreation's comments on the final EIS that strict adherence to the *Karst Mitigation Plan* is essential to minimizing impacts on sensitive karst areas. We also believe that, with appropriate implementation of the *Karst Mitigation Plan*, the proposed AP-1 pipeline route does not require modification. As stated in the final EIS, the Virginia Department of Conservation and Recreation Division of Natural Heritage and the Virginia Cave Board have endorsed the *Karst Mitigation Plan* as comprehensive and indicate that the measures included would reduce the potential risk posed by the ACP Project to karst resources.[296]

iii. Acid-Producing Rock

207. EPA recommends that, prior to construction, Atlantic complete surveys (beyond desktop analysis) where the AP-1 mainline crosses reclaimed coal surface strip mines, and identify measures to be implemented in the event acid-producing rock is encountered; and that these measures be included in any project approval, or in an appropriate construction and mitigation plan. The final EIS summarizes Atlantic's and DETI's consultation with geologic experts to identify geologic formations crossed by the projects that are known to contain acid-producing minerals, and presents mitigation measures committed to by Atlantic and DETI. Such measures include surveys for acid rock drainage, limiting the duration of stockpiled materials to less than 30 days to minimize potential for acid rock drainage, and applying lime or replacing topsoil with acid-free topsoil.[297] We find these measures to be sufficient.

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[294] Light Imaging, Detection, And Ranging, or LiDAR, is a remote sensing method used to examine the surface of the Earth, often used to develop 3-dimensionsal images or maps of Earth features.

[295] Dye tracing studies encompass a wide variety of techniques that can be used to track or model groundwater flow, either quantitatively or qualitatively. In groundwater karst systems, it can be effective in determining connectivity of underground systems or pathways of groundwater flow.

[296] Final EIS at 4-177.

[297] *Id.* at 4-32 through 4-34.

iv. Mining Operations

208. After the issuance of the final EIS, Western Pocahontas Properties (WPP) filed comments regarding ongoing and future plans for coal mining on its properties. In sum, WPP states that the ACP Project route, as proposed, would interfere with several locations in which WPP plans to actively mine coal resources. WPP states that the pipeline as currently routed would prohibit WPP's mining activities, given restrictions on blasting by Atlantic, and would pose safety concerns to the pipeline and the mine. To address these concerns, WPP requests that the Commission adopt an alternative route that WPP now submits for consideration.

209. Section 4.1.4.5 and Appendix Z of the final EIS discusses concerns related to active mineral mining, which includes comments filed by WPP on the draft EIS. The final EIS noted that based upon consultations by Atlantic and DETI with mine owners and operators of active mines in the project area, it appears that those mines are of a design that locates shafts hundreds of feet below the ground surface. Thus, the final EIS concluded that the project would neither conflict with mining activities nor pose a public safety concern.[298] WPP's comments do not provide sufficient information about the depth or specific design of its mining operations for us to definitively conclude whether the ACP Project would conflict with WPP's mining operations. However, depending on the specific mine type and design, we do acknowledge that the project could impact WPP's ability to extract some of the coal resources on its properties. We note that the specific alternative submitted by WPP would result in impacting additional landowners and merely shift the projects impacts to a new group of landowners who have not had the opportunity to participate in the Commission's environmental review process or provide comments. Further, while we believe it may be possible to develop a more modest route deviation that would avoid impacts on the locations from which WPP plans to extract mineral resources, we are unable to do so at this time due to the illegibility and insufficient level of detail of the mapping provided by WPP.

210. Accordingly, while we are not approving WPP's requested alternative, we believe WPP's concerns can be addressed through ongoing consultations between Atlantic and WPP, and that minor alignment shifts and mitigation measures specific to construction in areas of active mining can be developed. Therefore, we have added Environmental Condition 73 that requires Atlantic to develop a Mining Area Construction Plan and provide documentation of ongoing consultation with WPP regarding minor alignment shifts to avoid planned mining efforts.

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[298] *Id.* at 4-35.

c. **Water Resources**

i. **Groundwater**

211. Bedrock aquifers predominate in the project areas, with minor surficial alluvial aquifers occurring along streams. The pipeline trench will rarely exceed 10 feet in depth, but could encounter shallow groundwater. In those situations, the trench will be dewatered through filters into adjacent vegetated uplands so that there will be some recharge to shallow aquifers.

212. The ACP Project pipeline route will also cross four wellhead protection areas[299] in West Virginia and two in Virginia.[300] No groundwater source protection areas were identified in the vicinity of the Supply Header Project.

213. Current survey information has identified 4 public and 236 private water supply wells near the ACP Project, and 18 private wells near Supply Header Project.[301] One of the public wells and 12 of the private wells are within the ACP Project workspace, and one is within the Supply Header Project workspace. A total of 124 springs were identified near the ACP Project, and 4 springs were identified near Supply Header Project.[302] The Virginia Department of Health's Office of Environmental Health Services provided comments related to existing wells and water supplies. Specifically, the Office of Environmental Health Services recommended that surveys for wells and springs be completed prior to construction. Due to lack of landowner permission and survey access, Environmental Condition 52 in the appendix to this order requires Atlantic and DETI to complete and file the remaining survey results for wells and springs after this order is issued. The Office of Environmental Health Services also recommended that Atlantic conduct a sanitary survey for sewage systems near the pipeline's final path. Atlantic committed to route around onsite sewage systems if possible, and to work with property owners to relocate onsite sewage systems that cannot be avoided. If previously unidentified sewage systems are encountered, we believe that Atlantic's commitment to relocate any system would resolve any issues, or that reroutes would be accommodated under Environmental Condition 5.

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[299] A wellhead protection area encompasses the area around a drinking water well where contaminants could enter and pollute the well. Final EIS at 4-78.

[300] *Id.* at 4-79.

[301] *Id.* at 4-80.

[302] *Id.*

214. Commenters noted the degree of groundwater interconnectivity in areas of karst terrain. Commenters also stated that many landowners depend on wells or springs sourced from karst-generated groundwater for their domestic drinking water supplies, livestock watering, and irrigation of agricultural lands. Because karst features provide a direct connection to groundwater, there is a potential for pipeline construction to increase turbidity in groundwater, due to runoff of sediment into karst features or to contaminate groundwater resources by inadvertent spills of fuel or oil from construction equipment. To minimize impacts on wells, springs, and karst-related groundwater from construction-associated sedimentation and runoff, Atlantic and DETI have committed to implement the erosion control measures outlined in their *Karst Mitigation Plan* as well as the measures in the Commission's *Upland Erosion Control, Revegetation, and Maintenance Plan* (FERC Plan). Further, to minimize the potential for hazardous materials to contaminate groundwater, Atlantic and DETI will implement the measures outlined in their *Stormwater Pollution Prevention Plan*; *Spill Prevention, Control, and Countermeasures Plan*; *Contaminated Media Plan*; and *Blasting Plan*.

215. Atlantic and DETI have begun and will continue to conduct pre-construction water quality evaluations on water wells and springs within 150 feet of the construction workspace (500 feet in karst terrain), and will complete post-construction testing for damage claims during and after construction. Environmental Condition 68 requires Atlantic and DETI to offer post-construction testing of water supplies to all landowners within 150 feet of the construction workspace (500 feet in karst terrain). EPA suggested that the applicants develop a "communication plan" for conveying the information related to well testing with landowners. We believe that providing this information is important to landowners, but we find it unduly burdensome to require the development of an additional plan here. Atlantic and DETI have committed to providing information regarding well testing to landowners, and they are required to do so by this order. Additionally, Environmental Condition 9 requires Atlantic and DETI to develop a complaint resolution procedure, which would provide landowners recourse to secure copies of the reports if they are not provided or solicit the aid of Commission staff. In situations where project-related construction damages the quantity or quality of water supplies, the applicants have committed to compensate the landowner for damages, repair or replace the water systems to pre-construction conditions, and provide temporary sources of water.

ii. Surface Waters and Fisheries

216. The ACP Project will require 1,536 crossings of surface waterbodies, 587 of which are perennial and 18 of which are defined by the Commission as major waterbodies (more than 100 feet wide).[303] The ACP Project pipeline route will cross

[303] *Id.* at 4-100 through 4-103.

17 waterbodies listed on the Nationwide Rivers Inventory maintained by the National Park Service of rivers with outstanding qualities that may qualify for wild, scenic, or recreational designation; 12 federal navigable waters; as well as numerous state-designated waterbodies.[304] Atlantic will cross waterbodies using a variety of methods, including the wet open-cut, dry open-cut (flumed, dam-and-pump, or cofferdam), horizontal directional drill (HDD), and bore methods. All navigable water crossings will be completed via HDD or the cofferdam method.

217. The Supply Header Project will require 133 crossings of intermediate and minor surface waterbodies, of which 115 are perennial.[305] DETI will cross waterbodies using either dry open-cut or bore crossing methods.

218. Nine public surface water intakes are within 3 miles downstream of the ACP Project route, and one is within 3 miles downstream of the Supply Header Project route.[306] Six source water protection watersheds will be crossed in North Carolina.[307] Atlantic and DETI will use dry and trenchless crossing methods at these crossings.

219. Trout, anadromous fish, or federal or state/commonwealth protected species are present in several waterbodies that will be crossed by the ACP and Supply Header projects. Atlantic and DETI will minimize aquatic resource impacts by using the various trenchless or dry crossing methods, extra workspace restrictions, and restoration procedures. Atlantic will implement mussel relocation in West Virginia, Virginia, and North Carolina, and will implement relocation plans for certain non-mussel species in Virginia and North Carolina. Atlantic and DETI will also implement measures outlined in their construction and restoration plans, such as restoring stream beds and banks to preconstruction conditions and implementing measures to minimize erosion and sediment loads. Where in-stream blasting may occur, Atlantic and DETI will implement blasting plans that provide measures for minimizing fishery impacts. Atlantic and DETI agreed to adhere to in-water work windows established by state resource agencies for crossing streams that contain or may contain sensitive species or special designations. However, given the number of waterbodies crossed, the final EIS concluded, and we agree, that certain designated water resources should be crossed with prescribed time of year restrictions to further avoid impacts on these resources. Therefore, Environmental

[304] *Id.* at 4-112 through 4-113.

[305] *Id.* at 4-100 through 4-103.

[306] *Id.* at 4-110 through 4-112.

[307] *Id.*

Condition 20 in the appendix to this order requires Atlantic and DETI to adhere to additional in-water work windows, as detailed in appendix K of the final EIS.

220. EPA recommended that the Neuse River crossing be completed via the HDD method, pending a hydrofracture study that indicates low risk of inadvertent release, or to use the direct pipe method if the risk is not shown to be low. Environmental Condition 35 requires Atlantic to file a hydrofracture potential analysis for the Neuse River (located at MP 98.5 on AP-2), and to utilize the HDD method at this crossing if the potential for hydrofracture is low. If the HDD method is not feasible, Environmental Condition 35 requires Atlantic to consult with the U.S. Fish and Wildlife Service and North Carolina Wildlife Resources Commission to identify additional conservation measures that Atlantic will implement at this crossing to mitigate for the potential impacts on Endangered Species Act-listed, proposed, and/or under review species.

221. In its comments on the final EIS, the Virginia Marine Resource Commission provided recommendations for measures to be implemented at two waterbody crossings, Quaker Swamp and Cohoon Creek, including erosion and sediment control measures outlined in an April 13, 2017 memorandum from Environmental Resources Management to DETI, as well as timing restrictions related to predicted rainfall events. In a letter dated April 13, 2017, from Atlantic to the Virginia Department of Environmental Quality, that included the Environmental Resources Management memorandum as an attachment,[308] Atlantic committed that, if weather forecasts indicate that heavy rainfall is predicted, trenching would not occur until the threat of rain has passed. Further, Atlantic agreed in its letter to improve erosion and sediment control measures, as outlined in the memorandum.

222. Atlantic and DETI will require a total of approximately 86.6 million gallons of water for hydrostatic testing (82.9 million gallons for the ACP Project and 3.7 million gallons for the Supply Header Project).[309] Of this volume, 46.9 and 39.7 million gallons will be required from municipal sources and surface water sources, respectively. Water for hydrostatic testing will be withdrawn and discharged in accordance with the Commission's *Wetland and Waterbody Construction and Mitigation Procedures* (FERC Procedures), state/commonwealth regulations, and required permits. Atlantic and DETI will construct temporary cylindrical water impoundment structures adjacent to several of the water withdrawal points to allow a slower withdrawal rate. As recommended by staff in the final EIS and adopted here, Environmental Condition 61 requires Atlantic and DETI to limit water withdrawal to not exceed 10 percent of instantaneous flow at

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[308] Atlantic's April 13, 2017 Letter to the Virginia Department of Environmental Quality (filed May 5, 2017).

[309] Final EIS at 4-121.

waterbodies that contain federally protected species.[310] Environmental Condition 17 requires Atlantic and DETI to identify proposed or potential sources of water used for dust control, anticipated quantities of water to be appropriated from each source, and the measures they will implement to ensure water sources and any related aquatic biota are not adversely affected by the appropriation activity.

223. We received comments regarding potential effects on surface waterbodies during construction and operation of the projects due to sedimentation or spills or leaks of hazardous materials. We also received comments after the issuance of the final EIS claiming that open-cut waterbody crossings would prevent navigation or migration of aquatic species and cause excessive upstream flooding. Studies show that dry open-cut waterbody crossings result in temporary (less than 4 days) and localized (for a distance of only a few hundred feet of the crossing) increases in turbidity downstream of construction. The magnitude of this increase is small in comparison to increased turbidity associated with natural runoff and precipitation events.[311] Once construction is complete, streambeds and banks will be restored. The FERC Procedures (at section V.C.1.) stipulate the use of clean gravel or native cobbles for the upper one foot of trench backfill in all waterbodies that are classified as coldwater fisheries. The FERC Procedures also stipulate that downstream flows must be maintained (for aquatic resources) and that crossings are designed to meet the maximum flows of the water body. Furthermore, these crossings would be subject to ongoing monitoring while flows are diverted to prevent any undue damming of waterbodies. Atlantic and DETI will minimize impacts on riparian vegetation at the edge of waterbodies by narrowing the width of the standard construction rights-of-way at waterbody crossings to 75 feet and by siting most temporary workspaces at least 50 feet away from stream banks. Atlantic and DETI will minimize impacts on surface waterbodies by implementation of the construction practices outlined in their project-specific construction plans, the FERC Plan and Procedures, and by adhering to state and federal construction, restoration, and operational requirements. To avoid or minimize the potential impacts of fuel or oil or other hazardous materials spilled from construction equipment, Atlantic and DETI will follow the procedures outlined in their *Spill Prevention, Control, and Countermeasures Plan*, which includes both preventative and mitigation measures such as personnel training, equipment inspection, refueling procedures, and spill cleanup and containment. Additionally, Atlantic and DETI will employ onsite environmental inspectors who will

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[310] The VA Department of Game and Inland Fisheries noted it was unable to confirm whether this was required in the final EIS, and we confirm here that Atlantic will be required to adhere to this measure.

[311] See Final EIS at 4-229.

ensure that the applicants follow their construction plans and adhere to the environmental conditions described in this order.

224. In addition to the measures we require here, the U.S. Army Corps of Engineers as well as the Pennsylvania Department of Environmental Protection, West Virginia Department of Environmental Protection, Virginia Department of Environmental Quality, and North Carolina Department of Environmental Quality, have the opportunity to impose conditions to protect water quality pursuant to section 401 and 404 of the Clean Water Act. We expect strict compliance by the applicants with any such conditions.

iii. <u>Wetlands</u>

225. Construction of the ACP and Supply Header projects will impact a total of 798.2 acres of wetlands, including 91 acres of emergent wetlands, 97.4 acres of scrub-shrub wetlands, and 604.1 acres of forested wetlands.[312] Construction of the projects' aboveground facilities will result in the loss of 7.4 acres of wetlands.[313] To ensure this loss of wetlands is appropriately mitigated, Environmental Condition 53 in the appendix to this order requires Atlantic and DETI to file a copy of their final wetland mitigation plans and documentation of U.S. Army Corps of Engineers approval of the plans prior to construction. The remainder of wetlands will be restored after pipeline installation. However, in some cases there will be conversions of wetland types and functions.

226. EPA recommended continued efforts, including route modifications, to avoid and minimize impacts on cypress gum swamps, riparian habitats, and other special aquatic habitats. As stated in the final EIS in response to EPA's comments on the draft EIS,[314] impacts on these and other sensitive wetlands would be avoided, minimized, and/or mitigated through the U.S. Army Corps of Engineers' section 404 and 401 review and permit process. The final wetland mitigation plan, and U.S. Army Corps of Engineers' approval, would include appropriate mitigation for impacts on forested and high quality wetland resources.

227. Within the 10-foot-wide corridor centered on the pipelines that is mowed on a regular basis in accordance with the FERC Procedures, there will be a permanent conversion of forested and shrub wetlands to herbaceous wetlands. Impacts on emergent and scrub-shrub wetlands within temporary workspaces will be short-term. After construction, those areas will be restored, with emergent and scrub-shrub wetlands

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[312] Final EIS at 4-135.

[313] *Id.* at 4-139.

[314] *Id.* at Attachment Z, page 53.

returning to their original condition and function within a few years. Forested wetlands within temporary workspaces will be subject to long-term impacts. While trees could regenerate in those areas, it will take decades for them to mature and return the forested wetlands to their original condition and function.

228. In general, construction and operation-related impacts on wetlands may also be mitigated by the applicants' compliance with the conditions of the Clean Water Act sections 404 and 401 permits. For unavoidable wetland impacts, Atlantic and DETI commit to purchase wetland and stream credits from approved mitigation banks in the respective states. In-lieu fee state programs may also be considered.[315] Proof of compensatory mitigation credit purchase will be provided by the applicants to the U.S. Army Corps of Engineers prior to construction. With implementation of the acceptable avoidance and minimization measures, as well as the environmental conditions of this order, we agree with the final EIS's conclusion that the ACP and Supply Header projects would not significantly impact wetlands.[316]

d. Vegetation, Forested Land, and Wildlife

229. Construction of the ACP Project will affect 5,522 acres of forest, 379 acres of shrublands, and 226 acres of grasslands.[317] Operation of the ACP Project will affect about 2,455 acres of forest, 172 acres of shrublands, and 101 acres of grasslands.[318] About 532 acres of forest will be permanently converted to industrial land use at aboveground facilities and permanent access roads for the ACP Project.

230. Construction of the Supply Header Project will affect a total of about 614 acres of forest, 6 acres of shrublands, and 226 acres of grasslands.[319] Operation of the Supply Header Project will affect about 290 acres of forest, 175 acres of shrublands, and

[315] In-lieu-fee programs may be used pursuant to an agreement between a regulatory agency or agencies in which an external mitigation sponsor collects funds from permittees (applicant) in lieu of the permitees providing their own permittee-responsible compensatory mitigation that would be required for their U.S. Army Corps of Engineers permit. The external sponsor can then use those collected funds from multiple applicants or permittees to create one or more mitigation sites.

[316] Final EIS at 4-140.

[317] *Id.* at 4-155 through 4-156.

[318] *Id.*

[319] *Id.*

101 acres of grasslands.[320] About 97 acres of forest and 2 acres of shrublands will be permanently converted to industrial land use at aboveground facilities and permanent access roads for the Supply Header Project.

231. The ACP Project will pass through several managed or vegetation communities of special concern, including the James River and Horsepen Wildlife Management Areas; the Kumbrabow and Seneca State Forests; the Monongahela National Forest and George Washington National Forest; late seral forests; 16 Natural Heritage Conservation Sites in Virginia; and 12 natural heritage natural areas and 9 natural communities in North Carolina. The Supply Header Project will pass through the Lewis Wetzel Wildlife Management Area in West Virginia. Since the issuance of the final EIS, the Virginia Department of Conservation and Recreation has identified three new stream conservation units (Spruce Creek, Matthews Creek, and Kingsale Swamp) and two new conservation sites (Duncan Knob Access Road and Wilson Mountain) that would be crossed by the AP-1 mainline. Atlantic will be required to implement the agency-recommended time of year restrictions and crossing measures, and comply with the restoration requirements, that were developed in consultation with resources agencies and contained in the FERC Plan and Procedures when crossing the newly identified stream conservation units.

232. The Virginia Department of Conservation and Recreation reiterated its previous comments that a hydrologic study of the Emporia Powerline Bog and Handsom-Gum Powerline Conservation Sites is essential to determine appropriate construction and restoration measures within these conservation sites. Atlantic has committed to completing hydrologic surveys of these sites, but does not propose to do so until the second quarter of 2018. To ensure that construction and restoration measures can be developed in coordination with the Virginia Department of Conservation and Recreation, Environmental Condition 60 requires Atlantic to complete the hydrologic studies of these sites prior to any construction within these conservation sites, and to file the results of the studies, along with construction and restoration measures developed in consultation with the Virginia Department of Conservation and Recreation, for Commission staff review.

233. The 50-foot-wide operational pipeline easements in uplands will be kept clear of trees, resulting in the permanent conversion of forest to grasslands/shrub land use. The remainder of the temporary construction workspace along the pipeline routes in forested uplands will be allowed to regenerate; although it will take many years for trees to mature. This will be a long-term impact affecting about 2,772 acres of forest, but the resource will eventually recover. The removal of interior forest in order to create the necessary pipeline rights-of-way will result in the conversion of forest area to a different vegetation type. This will contribute to forest fragmentation and the creation of forest edges, which will remove habitat for interior species.

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[320] *Id.*

234. The ACP Project pipeline route will cross seven EPA Level III ecoregions: the Western Allegheny Plateau, Central Appalachians, Ridge and Valley, Blue Ridge Mountains, the Piedmont, Southeastern Plains, and Middle Atlantic Coastal Plain. All components for the Supply Header Project will be within the Western Allegheny Plateau ecoregion. Combined, these ecoregions make up a total area of more than 200 million acres, of which more than 120 million acres is forested. In considering the total acres of forest affected by the projects, the quality and use of forest for wildlife habitat, and the time required for full restoration in temporary workspaces, we agree with the final EIS's conclusion that the projects will have significant impacts on forest.[321]

235. EPA recommended that in forested areas, the permanently-maintained right-of-way be kept to the narrowest width possible. As described in the final EIS, Atlantic would generally maintain a permanent corridor of 50 feet, and a narrower corridor in sensitive areas such as wetlands. Atlantic's permanent right-of-way will be reduced significantly from the construction right-of-way, which typically measures 125 feet in width. A maintained corridor is important to facilitate routine and thorough inspections of the pipeline by its operator. These inspections are required by federal law to ensure safe operation of the pipeline and ensure an adequate degree of public health and safety. Given these considerations and because the width of the right-of-way has been reduced to the minimum necessary, we do not find it reasonable or practical in this instance to require further reductions in the width of the right-of-way.

236. To minimize forest fragmentation and edge effects, Atlantic has collocated about 9 percent and DETI 31 percent of the pipeline routes with existing linear corridors. Atlantic and DETI will seed and install temporary and permanent erosion control measures according to their *Restoration and Rehabilitation Plan,* the FERC Plan and Procedures, and the *Construction, Operation, and Maintenance Plan*, which is being developed by the applicants in coordination with the Forest Service. Atlantic and DETI have also developed an *Invasive Species Management Plan*. Environmental Condition 18 in the appendix to this order requires Atlantic and DETI to revise their *Restoration and Rehabilitation Plan* and *Invasive Species Management Plan* to minimize and/or restrict herbicide, pesticide, and insecticide applications.

237. The Virginia Forest Conservation Partnership recommended that an additional forest fragmentation analysis be completed using Virginia Forest Conservation Partnership methodologies, and that mitigation, including compensatory mitigation, be provided for direct and indirect impacts on forests. The final EIS assesses the fragmentation and edge effect impacts that would result from construction and operation of the pipeline using similar methodologies recommended by the Virginia Forest Conservation Partnership, and presents measures committed to by Atlantic and DETI that

[321] *Id.* at 4-170.

would be implemented to minimize or avoid fragmentation impacts.[322] Specifically, the final EIS concluded that the ACP Project would result in the loss of interior forest habitat, creation of new forest edges, fragmentation of forest cores, and reduction in the size of forest cores.[323] Atlantic has committed to incorporating mitigation measures including: (1) using regionally-specific flowering plant seed mixes to provide food and habitat for pollinators and local wildlife species; (2) mitigating for impacts on sensitive environmental resources including listed species habitats and migratory birds; (3) restricting maintenance mowing to occur outside of the bird nesting season for migratory birds; (4) identifying conservation easements or sites where forested areas could be restored; and (5) acquiring a 400-acre conservation site adjacent to the Monongahela National Forest to provide offsite mitigation.[324] The Commission does not require or encourage applicants to participate in compensatory mitigation to groups, governments, or agencies. The mitigation measures proposed or recommended in the final EIS's analysis target specific natural resources. The final EIS concludes, and we agree, that despite the mitigation measures that would be implemented in Atlantic's and DETI's construction and restoration plans and conditions of this order, forested areas would experience long-term to permanent significant impacts as a result of fragmentation.[325]

238. EPA, Virginia Department of Conservation and Recreation, and Virginia Department of Game and Inland Fisheries recommended that an expanded list of invasive and noxious plant species be included in the *Invasive Plant Species Management Plan*. The nine species of noxious weeds identified in Atlantic's *Invasive Plant Species Management Plan* are consistent with the Virginia Administrative Code and with those species identified during correspondence with the program manager for the Virginia Department of Agriculture and Consumer Services. Although the *Invasive Plant Species Management Plan* does not include an expanded list of non-regulated invasive and noxious weeds, many of the measures included in Atlantic's plan will aid in minimizing the spread of non-regulated species in addition to the regulated species. Additionally, restoration measures outlined in the FERC Plan and Procedures require that the restored right-of-way must have a similar density and cover of non-nuisance vegetation as compared to adjacent undisturbed areas. We find these measures sufficient.

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[322] *Id.* at 4-187 through 4-202.

[323] *Id.* at 4-200.

[324] *Id.* at 4-202.

[325] *Id.* at 5-14.

239. In its comments on the final EIS, the Virginia Department of Game and Inland Fisheries reiterated its comments on the draft EIS[326] regarding identification of invasive aquatic plant species of concern that may occur in the ACP Project corridor, and recommended measures to be included in an invasive species plan. The final EIS acknowledges the comments of the Virginia Department of Game and Inland Fisheries in the discussion of invasive aquatic species.[327] Further, the final EIS notes that Atlantic and DETI would control the potential transport of invasive aquatic species through adherence to federal and state-specific regulations for preventing the land transport of such species by primarily utilizing municipal sources of water for HDDs, hydrostatic testing, and dust control, and, where sourced from surface waters, by discharging hydrostatic test waters into well-vegetated upland areas.[328] We also will require Atlantic and DETI to include with their Implementation Plans measures to control the spread of invasive aquatic species and procedures for notifying federal and state agencies should invasive aquatic species be identified during construction.

240. A variety of wildlife species occupy the ecoregions and habitats to be crossed by Atlantic's and DETI's pipelines. Construction of the projects may result in limited mortality for less mobile animals, such as small rodents, reptiles, amphibians, and invertebrates, that are unable to escape equipment. More mobile animals will likely be displaced to adjacent similar habitats during construction. Once the right-of-way is revegetated, it will be reoccupied by the displaced wildlife.

241. The ACP Project could have significant adverse impacts on karst, cave, and other subterranean habitat, as well as on the species associated with such habitat. Subterranean species are often located in only a few locations and are vulnerable to changes in hydrological pattern or water quality. Impacts associated with construction activities could have population-level impacts on these species (such as cave-adapted amphipods).

242. Additionally, constructing the projects could disrupt bird courting, breeding, or nesting behaviors. Migratory birds, including Birds of Conservation Concern, are associated with the habitats that will be affected by the projects. Three Bird Conservation Regions will be crossed by the ACP Project: Bird Conservation Regions 27 (Southern Coastal Plain), 28 (Appalachian Mountains),[329] and 29 (Piedmont). In

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[326] These comments were addressed by Atlantic and DETI. *See* Final EIS at Attachment Z, page 248.

[327] *Id.* at 4-238.

[328] *Id.* at 4-239.

[329] Bird Conservation Region 28 (Appalachian Mountains) will also be crossed by the Supply Header Project.

addition, 10 Important Bird Areas will be crossed by the projects. Atlantic and DETI developed a *Migratory Bird Plan* to minimize impacts on bird species, and have agreed to conduct tree clearing outside of state-specific migratory bird nesting seasons. Our Environmental Condition 19 requires Atlantic and DETI to revise their *Migratory Bird Plan* and address potential impacts on active rookeries. Additionally, on August 29, 2017, the Forest Service provided supplemental comments on the *Migratory Bird Plan*, offering minor textual revisions and improvements. We recognize these additions may have some benefits; therefore, we have modified Environmental Condition 19 to include the Forest Service in any of Atlantic and DETI's ongoing consultations with state wildlife agencies.

e. **Threatened, Endangered, and Other Special Status Species**

243. Commission staff identified 36 federally listed threatened or endangered species (or federal candidate species or federal species of concern) that could be present in the vicinity of the projects.[330] However, four of these species do not occur in the specific project area. Of the remaining 32 species, the final EIS concludes that the ACP Project would have no effect on 11 species, would not be likely to adversely affect 14 species, and would be likely to adversely affect 7 species (Indiana bat, northern long-eared bat, Roanoke logperch, Madison Cave isopod, clubshell mussel, small whorled pogonia, and running buffalo clover).[331] The final EIS further evaluated designated critical habitats[332] for the Indiana bat and Atlantic Sturgeon and concluded that construction and operation of the ACP Project would have no effect on U.S. Fish and Wildlife designated critical habitat for the Indiana bat and would not adversely modify U.S. Fish and Wildlife designated critical habitat for the Atlantic sturgeon.[333] The final EIS concludes that the Supply Header Project would not likely adversely affect two mussels, but would likely adversely affect the Indiana bat and northern long-eared bat.[334] The conclusions by Commission staff in the final EIS were based in part upon Atlantic's and DETI's

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[330] Final EIS at 4-247 through 4-250.

[331] *Id.* at ES-7.

[332] Not all threatened or endangered species have U.S. Fish and Wildlife Service designated critical habitats. However, for species that do have designated critical habitats, the action agency must evaluate a project's effects on designated habitat(s) in addition to the effects on the species itself.

[333] *Id.* at 4-269 and 4-286.

[334] *Id.* at 4-269 and 4-277.

commitments for implementing certain species-specific avoidance and minimization measures. Commission staff has submitted a Biological Assessment to the U.S. Fish and Wildlife Service that includes a detailed assessment regarding the effects of the projects on federally listed species, initiating formal consultation with the U.S. Fish and Wildlife Service regarding species that will likely be adversely affected by either the ACP or Supply Header project. Environmental Condition 54 in the appendix to this order stipulates that construction cannot begin until after staff completes the process of complying with the Endangered Species Act.

244. We clarify that the final EIS requires that electric resistivity studies and/or air track drilling surveys of karst features identified within the construction workspace and within 5 miles of known or survey-identified bat hibernacula be completed for all project areas, not just for those areas that have been or would be surveyed in 2017. Accordingly, Environmental Condition 64 of this order has been revised to clarify this requirement.

245. The projects will also affect, to varying degrees, over one hundred species that are state-listed as threatened, endangered, or were noted by the applicable state agencies as being of special concern (in addition to those species already counted as federally listed). The final EIS concludes that that for species with high site fidelity and/or limited mobility (such as isopods), construction activities could impact and alter their habitat or cause localized population declines or local extirpations.[335] Atlantic and DETI will implement various construction plans to minimize impacts on these species.[336] Additional species-specific conservation measures that would be implemented by Atlantic and DETI are described in Appendix S of the final EIS.[337]

f. <u>Land Use, Recreation, and Visual Resources</u>

246. The ACP Project pipeline route will mostly cross forest (56.1 percent), followed by agricultural land (27.7 percent), and wetlands (8.6 percent).[338] The Supply Header

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[335] *Id.* at 4-342.

[336] The following plans all have measures that will help minimize impacts: the FERC Plan and Procedures; the *Restoration and Rehabilitation Plan*; the *HDD Plan*; the *Karst Mitigation Plan*; the *Spill Prevention, Control, and Countermeasures Plan*; the *Timber Removal Plan*; the *Invasive Plant Species Management Plan*; the *Blasting Plan*; the *Migratory Bird Plan*; the *Protected Snake Conservation Plan*; the *Fire Plan*; the *Fugitive Dust Control and Mitigation Plan*; and the *Construction, Operations, and Maintenance Plan* (on National Forest lands).

[337] *Id.* at Appendix S.

[338] *See id.* at 4-344 through 4-349.

Project pipeline route will mostly cross forest (88.4 percent), followed by agricultural land (7.1 percent), and developed lands (3.6 percent).[339]

247. Combined, both projects will affect about 3,453 acres of agricultural lands.[340] Impacts on agricultural lands will be short-term, lasting during the period of construction and restoration and returning to pre-construction conditions within a few years. The applicants have committed to compensate farmers for the loss of agricultural production during the construction and restoration period. Following pipeline installation, the right-of-way will be restored to near pre-construction conditions and use, and agricultural practices could resume. Except for orchards, crops and pasture can be planted directly over the entire right-of-way. Mitigation measures typically implemented in agricultural lands (as specified in the FERC Plan) include topsoil segregation, rock removal, soil decompaction, and repair/replacement of irrigation and drainage structures damaged by construction. Environmental Condition 40 in the appendix to this order requires Atlantic to develop site-specific *Organic Farm Protection Plans* that outline measures to be implemented when crossing organic farms.

248. Atlantic identified 77 residences and DETI identified 5 residences within 50 feet of their respective proposed construction rights-of-way.[341] Site-specific residential mitigation plans are included as appendix J1 of the final EIS. The final EIS concludes that with implementation of Atlantic's and DETI's mitigation measures, including the construction methods in residential areas, and Landowner Complaint Resolution Procedures, impacts on residences would be minimized or mitigated.[342] We agree.

249. Federally owned or managed recreational and special use areas that will be crossed by the ACP Project pipeline route include the Appalachian National Scenic Trail, Blue Ridge Parkway, Monongahela National Forest, and George Washington National Forest. The Blue Ridge Parkway, managed by the National Park Service, and the Appalachian National Scenic Trail, managed by the Forest Service, will be crossed under with an HDD, eliminating any surface impacts on either the Blue Ridge Parkway or the Appalachian National Scenic Trail. Construction and operation of the pipeline under the Appalachian National Scenic Trail and Blue Ridge Parkway will also not have a significant visual impact. Additionally, the final EIS discussed contingency planning for

[339] *See id.*

[340] *Id.* at 4-349.

[341] *See id.* at 4-374 through 4-375.

[342] *Id.* at 4-377.

the HDD crossing of the resources, as well as an analysis of alternate crossing locations of the Blue Ridge Parkway and Appalachian National Scenic Trail.

250. The ACP Project pipeline route will pass through the Monongahela National Forest and George Washington National Forest for a total of 5.2 miles and 16.0 miles, respectively. As listed on table 2.2-2 of the final EIS, the ACP Project will affect about 112 acres in the Monongahela National Forest and 318 acres in the George Washington National Forest during construction.[343] The Monongahela National Forest and George Washington National Forest operate under Land and Resource Management Plans. The Forest Service analyzed amending its Management Plans to allow for the project within the Monongahela National Forest and George Washington National Forest, and on June 21, 2017, issued a draft record of decision to authorize the use and occupancy of National Forest System lands for the ACP Project. The draft record of decision was available for public objections until September 5, 2017. After resolving objections, the Forest Service will issue a final decision on the respective authorizations before it. Impacts on National Forest resources will be minimized by Atlantic following the measures outlined in its *Construction, Operation, and Maintenance Plan*.

g. <u>Socioeconomics</u>

i. <u>Property Values, Mortgages, and Insurance</u>

251. Several commenters expressed concerns regarding the potential effect of the projects on property values, mortgages, and homeowner's insurance. The final EIS identifies ten studies that conclude that the presence of a pipeline or compressor station either has no effect or an insignificant effect on property values.[344] Commenters cite a study performed by Key-Log Economics LLC,[345] which they assert demonstrates that property values will decrease as result of the proposed project. As stated in the final EIS, the Key-Log Study provides anecdotal evidence regarding sale value of properties, but does not present sources for the data presented with regard to loss of property value due to proximity to a pipeline.[346] Accordingly, we conclude here, as we have in other cases,

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[343] *Id.* at 2-18.

[344] However, the final EIS acknowledges that specific valuation predictions cannot be made on a property-by-property basis. *Id.* at 4-504 through 4-506.

[345] Key-Log Economics LLC, *Economic Costs of the Atlantic Coast Pipeline* (Feb. 2016) (filed Feb. 16, 2016) (Key-Log Study).

[346] For example, the Key-Log Study uses opinion surveys of realtors in Wisconsin to support its claims. However, these surveys are strictly personal opinion and do not

that the proposed project is not likely to significantly impact property values in the project area.[347]

252. With regard to concerns regarding to homeowner's insurance, our staff has researched this extensively and has found no evidence of any practices by mortgage companies to re-categorize properties, nor are we aware of federally insured mortgages being revoked, based on proximity to pipelines.[348] Accordingly, the final EIS concludes, and we agree, that homeowners' insurance rates are unlikely to change due to construction and operation of the proposed projects.[349]

ii. <u>Environmental Justice</u>

253. Executive Order 12898 requires that specified federal agencies make achieving environmental justice part of their missions by identifying and addressing, as appropriate, disproportionately high and adverse human or environmental health effects of their programs, policies, and activities on minorities and low income populations.[350] The Commission is not one of the specified agencies and the provisions of Executive Order 12898 are not binding on this Commission. Nonetheless, in accordance with our usual practice, the final EIS addresses this issue.[351]

254. In accordance with EPA guidance,[352] the final EIS followed a three step approach for environmental justice reviews: (1) determine the existence of minority and low-

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carry with them the rigors of statistically developed and controlled studies. Final EIS at 4-504.

[347] *See, e.g., Transcontinental Gas Pipe Line Company, LLC*, 158 FERC ¶ 61,125 at P 106; *Central New York Oil & Gas Co., LLC*, 116 FERC ¶ 61,277, at P 44 (2006).

[348] Final EIS at 4-506. *See also Transcontinental Gas Pipe Line Company, LLC*, 158 FERC ¶ 61,125 at PP 107-108.

[349] Final EIS at 4-506.

[350] Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations, Executive Order 12,898 (Feb. 11, 1994), reprinted at 59 Fed. Reg. 7629.

[351] Final EIS at 4-511 through 4-515.

[352] EPA, *Final Guidance for Incorporating Environmental Justice Concerns in EPA's NEPA Compliance Analyses* (April 1998).

income populations in the project area; (2) determine if the resource impacts are *high and adverse*; and (3) determine if any identified high and adverse impacts fall disproportionately on environmental justice populations. If the federal agency finds that any of these conditions are not present, the agency may then conclude its review and determine the action is not sited in a discriminatory manner on low-income or minority communities.

255. The construction and operation of the proposed facilities would affect a mix of racial/ethnic and socioeconomic areas in the ACP and Supply Header project area.[353] However, not all impacts identified in the final EIS would affect minority or low-income populations. The primary adverse impacts on the environmental justice communities associated with the construction of projects would be the temporary increases in dust, noise, and traffic from project construction.[354] These impacts would occur along the entire pipeline route and in areas with a variety of socioeconomic background. We also received numerous comments expressing concern about minority and low income communities near the proposed Compressor Station 2 in Buckingham County, Virginia. Based on the methodology used in the final EIS, of the three census tracts within one mile of Compressor Station 2, one is a designated low-income community, and *none* of the tracts were designated as minority environmental justice populations.[355]

256. Atlantic and DETI would implement a series of measures that would minimize potential impacts on the communities, including environmental justice communities, near project facilities. For example, Atlantic and DETI propose to employ proven construction-related practices to control fugitive dust, such as application of water or other commercially available dust control agents on unpaved areas subject to frequent vehicle traffic. Similarly, Atlantic and DETI will implement noise control measures during construction and operation of the projects.

257. In response to comments regarding specific environmental health concerns of minority communities, including African American populations, the final EIS considered in greater detail the potential risks of impacts falling on these communities, and what those effects would be. Due to construction dust and compressor station emissions, African American populations[356] near ACP and Supply Header projects could experience

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[353] *Id.* at 4-512 through 4-513.

[354] *Id.* at 4-513.

[355] *Id.* at 4-513.

[356] As stated above, although minorities, including African Americans, do reside in the three census tracts within one mile of Compressor Station 2, none of the tracts were designated as minority environmental justice populations.

disproportionate health impacts due to higher rates of asthma within the overall African American community.[357] However, health impacts from construction dust would be temporary, localized, and minor. Health impacts from compressor station emissions would be moderate because, while they would be permanent facilities, air emissions would not exceed regulatory permittable levels. While the final EIS discusses the potential for the risk of impacts to fall disproportionately on minority communities, it further notes that, in relation to comments received regarding Compressor Station 2's effects on African Americans, the census tracts around the station are not designated as minority environmental justice populations. Therefore, by following the methodology outlined above, the final EIS concludes, and we agree, that the projects will not result in disproportionately high and adverse impacts on environmental justice populations as a result of air quality impacts, including impacts associated with the proposed Compressor Station 2.[358] Further, no disproportionately high and adverse impacts on environmental justice populations as a result of other resources impacts will be expected as a result of the projects.[359]

iii. Housing, Business, and Tourism

258. About 50 percent of the projects' workforce (5,815 workers) will be non-local, resulting in demand for local temporary housing in the projects' areas.[360] The final EIS estimates that there are at least 52,875 rooms/sites available in the project area, and there are sufficient accommodations to meet the increase in demand caused by the influx of the non-local construction workforce.[361] While some construction activity will be conducted during the peak tourism season, sufficient temporary housing is still likely to be available for tourists, however, it may be more difficult to find (particularly on short notice) or more expensive to secure. The final EIS concludes, and we agree, that the increase in demand for short-term housing from non-local construction workers during the construction of the projects would be temporary and minor.[362]

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[357] *Id.* at 4-514 (citing U.S. Dep't of Health and Human Services, Centers for Disease Control and Prevention, *Asthma Facts – CDC's National Asthma Control Program Grantees* (July 2013)).

[358] *Id.*

[359] *Id.* at 4-515.

[360] *Id.* at 4-492.

[361] *Id.*

[362] *Id.* at 4-492.

259. The projects will have economic benefits to local communities through expenditures on goods and services, including spending on hotels and restaurants, and tax revenues.[363] However, the final EIS acknowledges that some local businesses may be directly and indirectly impacted by the projects.[364]

260. The Commission received comments that the ACP Project would cause a delay or potentially prevent two large projects from being developed in the Rockfish Valley area. The first is the development of a self-described luxury hotel at Wintergreen Resort. Based on information provided by Wintergreen Property Owners Association Inc. and Wintergreen Resort Inc., the hotel would be located over one mile east of the ACP Project near AP-1 MPs 159.0 to 160.0. Wintergreen Pacific LLC and Pacific Group Resorts, the developers of the project, claim that they "would be forced to discontinue development of [the] hotel, or substantially delay its development" if the ACP Project is constructed. Commenters expressed concern regarding blocking access along Beech Grove Road leading to the resort area and hindering future development and sale of lots. Commenters also speculated that if the hotel at Wintergreen Resort was not developed, the value of the existing resort would diminish, impacting the future viability of the resort. Wintergreen Resort is cited as the largest employer in Nelson County, and commenters claimed that any diminishing value or opportunities for the resort could cause negative economic impacts for the entire Rockfish Valley area and the county, including the loss of property values if Wintergreen Resort went out of business.

261. The second development is the Spruce Creek Resort and Market, a proposed resort, hotel, restaurant, and public market on 100 acres of mature woodland along Virginia State Route 151 and bisected by Spruce Creek. Based on information provided by the developer, the AP-1 mainline would cross the resort between approximate MPs 162.4 and 162.7 in Nelson County, Virginia. The developer is concerned that ACP Project would cross the middle of the property, eliminating the attractiveness of the resort area and, thus, development of the resort would be stopped.

262. The final EIS concluded, and we agree, that construction of ACP Project and development of the hotel at Wintergreen Resort and the development of Spruce Creek Resort and Market could still be accomplished such that the overall socioeconomic impacts associated with the ACP Project are reduced or mitigated, while maintaining the appeal of the area, as demonstrated by other residential and commercial developments in the area of similar projects throughout the country.[365]

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[363] *Id.* at 4-510.

[364] *Id.* at 4-510.

[365] *Id.* at 4-510.

263. However, the final EIS acknowledges that the Spruce Creek Resort and Market could be impacted by the proposed projects.[366] Because of these impacts, Commission staff assessed other alternatives, primarily the "Spruce Creek Alternative," to avoid the proposed development. As further described in the final EIS, these other alternatives would result in similar but different impacts on a different set of landowners.[367] These included a privately-owned airstrip and various other local businesses or commercial endeavors, including Blue Heron Farms, High View Farm, Blue Toad Hard Cider, and a bed and breakfast. Commission staff concluded that the Spruce Creek Alternative did not offer a significant environmental advantage, and thus, did not recommend its adoption.

264. Commenters also indicated that construction and operation the projects could adversely impact local tourism. The final EIS found no evidence that short-term effects of pipeline construction have long-term significant impacts on the tourism industry in areas where pipeline construction has occurred. The final EIS concludes, and we agree, that recreational uses and tourism activities in the project area would not be affected by operation of the project.[368]

h. Cultural Resources

265. Atlantic identified 198 archaeological and historic sites within the area of potential effect for the ACP Project that are listed in the National Register of Historic Places (National Register), eligible for listing, are unevaluated, or would otherwise require treatment during construction (e.g., cemetery avoidance plans for cemeteries that are not eligible for listing).[369] State Historic Preservation Office (SHPO) concurrence with Atlantic's recommendations of eligibility is pending on most of these sites. Atlantic will avoid impacts on eligible or unevaluated cultural sites by project design, or will conduct additional studies to further assess National Register eligibility.

266. DETI identified two cultural resources sites that are recommended as eligible and will be avoided or mitigated during construction: one historic farmstead that is recommended as eligible, but will not be affected by the Supply Header Project; and

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[366] Specifically, the developer asserts in its comments that the development could lose up to 30 percent of its accommodations and its spa complex.

[367] Final EIS at 3-44.

[368] *Id.* at 4-497 through 4-500.

[369] *See id.* at 4-516 through 4-530.

three historic cemeteries that are recommended not eligible, but will be avoided during construction.[370]

267. The ACP Project pipeline route crosses two Historic Districts: Warminster Rural Historic District and South Rockfish Rural Historic District. Atlantic will assess potential effects on these historic districts, consult with the Virginia Department of Historic Resources and other interested parties as needed, and make recommendations for further evaluation or mitigation of adverse effects. Two access roads along the AP-3 pipeline will cross the Sunray Agricultural Historic District. Atlantic asserts that use of these roads will not affect the historic district. After the issuance of the final EIS, Roberta Koontz, co-owner of "The Wilderness," filed comments taking issue with Atlantic's survey of the property and Atlantic's recommendations regarding eligibility for listing in the National Register. The Virginia Department of Historic Resources commented that the property was determined eligible for listing on the National Register, and the Virginia Department of Historic Resources review board approved the nomination of "The Wilderness" for listing on the Virginia Landmarks Registry and the National Register. While discrepancies in the absolute boundaries of the parcel and exact location of structures are apparent, we clarify here, as did the final EIS, that the historic farmstead "The Wilderness" does meet the criteria for listing on the National Register and includes a residence, numerous outbuildings, and agricultural fields. Thus, the property will continue to be considered as part of staff's ongoing consultations under the National Historic Preservation Act. An assessment of effects and proposed mitigation for the historic property is required to be completed before project construction.

268. Atlantic and DETI consulted with 15 federally recognized Indian tribes to provide them an opportunity to comment on the projects. Several tribes and organizations requested additional information, and we have responded to tribes that commented on the projects. Atlantic and DETI have prepared plans to be used in the event any unanticipated archaeological sites or human remains are encountered during construction. The plans provide for work stoppage and the notification of interested parties, including Indian tribes, in the event of discovery.

269. Commission staff has not finished consultations with the SHPOs. In addition, Atlantic and DETI are still conducting investigations at sites where access was previously denied. If, in the future, Commission staff determines that any historic properties will be adversely affected, staff will notify the Advisory Council on Historic Preservation, and consult with appropriate consulting parties regarding the production of an agreement document to resolve adverse effects, in accordance with 36 C.F.R. § 800.6. The process of compliance with section 106 of the National Historic Preservation Act has not yet been completed for ACP and Supply Header projects. Therefore, Environmental Condition 56

[370] *See id*. at 4-530 through 4-535.

in the appendix to this order precludes construction until after any additional required surveys and evaluations are completed, survey and evaluation reports have been reviewed by the appropriate consulting parties, the Advisory Council on Historic Preservation has had an opportunity to comment, and the Director of OEP provides written notification to proceed.

i. Air Quality and Noise Impacts

i. Air Quality

270. Air quality impacts associated with construction of the projects will include emissions from construction equipment and fugitive dust. The final EIS concludes that such air quality impacts will generally be temporary, localized, and not have a significant impact on air quality or contribute to a violation of applicable air quality standards.[371] We agree.

271. Operational emissions will be mainly generated by the three new compressor stations for the ACP Project and the modification of four compressor stations for the Supply Header Project. Atlantic's proposed new Compressor Stations 1, 2, and 3 will be subject to a Prevention of Significant Deterioration (PSD) major source threshold of 250 tons per year. Potential operational emissions from the Crayne and JB Tonkin Compressor Stations after proposed modifications will remain below PSD major source thresholds; therefore, these stations will not be subject to PSD regulations. While emissions from the Mockingbird Hill Compressor Station will be minor, the net emissions increase of particulate matter, particulate matter with an aerodynamic diameter less than or equal to 10 microns, particulate matter with an aerodynamic diameter less than or equal to 2.5 microns, and greenhouse gasses (GHGs) will still exceed the major modification thresholds, representing a significant net emissions increase and requiring a Best Available Control Technology analysis. The Mockingbird Hill and JB Tonkin Compressor Stations are currently subject to Clean Air Act Title V regulations and will remain Title V facilities after construction. The Crayne Compressor Station, authorized under a state operating permit, is a minor source under Title V and will remain so after construction of the Supply Header Project. The final EIS concludes, and we agree, that emissions resulting from operation of the compressor stations will not cause or contribute to a violation of national air quality standards.[372]

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[371] *Id.* at 5-32.

[372] *Id.* at 4-561 and 4-563.

ii. Noise Impacts

272. Noise levels are quantified according to decibels (dB), which are units of sound pressure. The A-weighted sound level, expressed as dBA, is used to quantify noise impacts on people. Sound level increases during pipeline construction will be intermittent and will generally occur during daylight hours, with the possible exception of some HDD activities. Construction equipment noise levels will typically be around 85 dBA at a distance of 50 feet. Blasting may be necessary to trench through shallow bedrock. Blasting noise levels have been documented at about 94 dBA at a distance of 50 feet. Noise impacts during construction will be transient as pipe installation progresses from one location to the next. HDD operations at the entry and exit locations will result in high noise levels at the source location. Typically, noise from HDD operations is estimated to be about 90 dBA at 50 feet.

273. As stated in the final EIS, the applicants modeled noise levels at noise sensitive areas (NSA) near each compressor station during operation. Increases over existing ambient noise levels will be barely noticeable, ranging from 0.1 dBA to 8.5 dBA. "Worst case" modeled noise levels at each NSA due to typical compressor station operation will be below the Commission staff's noise limit of 55 dBA, with the exception of the JB Tonkin Compressor Station.[373] At the existing JB Tonkin Compressor Station, four NSAs currently experience total noise levels above the Commission staff guideline. However, after the proposed modifications, these NSAs will experience an overall *decrease* in noise ranging from 1.1 dBA to 3.9 dBA. Environmental Conditions 69, 70, and 72 in the appendix to this order require that the applicants file the results of noise surveys during operation of the compressor stations, and if noise exceeds the day-night sound level of 55 dBA at any NSA (or is above existing sound levels in the case of the existing NSAs at the JB Tonkin Compressor Station), the applicants must install additional noise controls and refile noise survey results a year later.

274. Therefore, the final EIS concludes, and we agree, that construction and operation the projects would not result in significant noise impacts on residents, and the surrounding communities.[374]

j. Safety

275. Numerous commenters questioned the safety of the projects. The final EIS notes that the project facilities must be designed, constructed, operated, and maintained to meet or exceed the U.S. Department of Transportation's (DOT) Minimum Federal Safety

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[373] *Id.* at 4-571 through 4-575.

[374] *Id.* at 4-576.

Standards[375] and other applicable federal and state regulations. These regulations include specifications for material selection and qualification; minimum design requirements; and protection of the pipeline from internal, external, and atmospheric corrosion.

276. Data reviewed by Commission staff and discussed in section 4.12 of the EIS support the conclusion that Commission-jurisdictional pipelines are a safe, reliable means of transporting natural gas. The rate of total fatalities for the nationwide natural gas transmission lines in service is approximately 0.01 per year per 1,000 miles of pipeline.[376] Using this rate, the 642.0-mile-long ACP and Supply Header projects' pipelines might result in a fatality (either an industry employee or a member of the public) on the pipeline every 156 years. Therefore, the final EIS concludes, and we agree, that the projects would represent only a slight increase in risk to the nearby public.[377]

277. We received comments during scoping and on the draft EIS from residents and emergency response representatives of Wintergreen Resort; Bath County, Virginia; and several community members and landowners regarding single-point access roads and the ability to evacuate in event of an emergency. Atlantic stated its intention is to work with local emergency responders to ensure they are comfortable with their ability to respond to a natural gas emergency, including evacuation, and by holding annual meetings and setting up table-top drills to work through the action items necessary to resolve a natural gas emergency scenario. Atlantic would also prepare *Operational Emergency Response Plans* in coordination with local emergency response providers. *The Operational Emergency Response Plans* would address incident evacuation requirements. Therefore, the final EIS concluded, and we agree, that operation of the project would represent only a slight increase in risk to the nearby public.[378]

278. We also received comments expressing concern that the ACP Project may become a target for a future act of terrorism. The likelihood of future acts of terrorism or sabotage occurring along the ACP or Supply Header Projects' pipelines or at any of the myriad natural gas pipeline or energy facilities throughout the United States is unpredictable given the disparate motives and abilities of terrorist groups. Further, the

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[375] *See* 49 C.F.R. pt. 192 (2017).

[376] Final EIS at 4-590.

[377] *Id.*

[378] *Id.* at 4-584; *see also EarthReports, Inc. v. FERC*, 828 F.3d 949, 959 (D.C. Cir. 2016) (the "opinions and standards of – and [the LNG operator's] future coordination with – federal and local authorities" were a reasonable component of the Commission's public safety evaluation).

Commission, in cooperation with other federal agencies, including the U.S. Department of Homeland Security, industry trade groups, and interstate natural gas companies, is working to improve pipeline security practices, strengthen communications within the industry, and extend public outreach in an ongoing effort to secure pipeline infrastructure. In accordance with the DOT surveillance requirements, the applicants will incorporate air and ground inspection of its proposed facilities into its inspection and maintenance program. Security measures at the new aboveground facilities will include secure fencing.

k. <u>Programmatic Environmental Impact Statement</u>

279. Several interveners and commenters contend that the Commission should prepare a programmatic EIS for natural gas infrastructure projects in the Marcellus and Utica Shale formations. Commenters argue that the CEQ recommends the use of a programmatic EIS in circumstances like those surrounding the ACP Project where "several energy development programs proposed in the same region of the country have similar proposed methods of implementation and similar best practices and mitigation measures that can be analyzed in the same document." Commenters argue that reviewing individual applications in isolation masks regional impacts. They note that other agencies, including the U.S. Department of Energy and the U.S. Bureau of Land Management, have used a programmatic EIS to address energy development issues on a regional basis.

280. CEQ regulations do not require broad or "programmatic" NEPA reviews. CEQ's guidance provides that such a review may be appropriate where an agency is: (1) adopting official policy; (2) adopting a formal plan; (3) adopting an agency program; or (4) proceeding with multiple projects that are temporally and spatially connected.[379] The Supreme Court has held that a NEPA review covering an entire region (that is, a programmatic review) is required only if there has been a report or recommendation on a proposal for major federal action with respect to the region.[380] Moreover, there is no

[379] Memorandum from CEQ to Heads of Federal Departments and Agencies, *Effective Use of Programmatic NEPA Reviews* 13-15 (Dec. 24, 2014) (citing 40 C.F.R. § 1508.18(b)), https://www.whitehouse.gov/sites/default/files/docs/effective_use_of_programmatic_nepa_reviews_18dec2014.pdf. We refer to the memorandum as 2014 Programmatic Guidance.

[380] *Kleppe v. Sierra Club*, 427 U.S. 390 (1976) (*Kleppe*) (holding that a broad-based environmental document is not required regarding decisions by federal agencies to allow future private activity within a region).

requirement for a programmatic EIS where the agency cannot identify projects that may be sited within a region because individual permit applications will be filed later.[381]

281. We have explained that there is no Commission plan, policy, or program for the development of natural gas infrastructure.[382] Rather, the Commission acts on individual applications filed by entities proposing to construct interstate natural gas pipelines. Under NGA section 7, the Commission is obligated to authorize a project if it finds that the construction and operation of the proposed facilities "is or will be required by the present or future public convenience and necessity."[383] What is required by NEPA, and what the Commission provides, is a thorough examination of the potential impacts of specific projects. As to projects that have a clear physical, functional, and temporal nexus such that they are connected or cumulative actions,[384] the Commission will prepare a multiple-project environmental document.[385] Such is not the case here.

282. The Commission is not engaged in regional planning. Rather, the Commission processes individual pipeline applications in carrying out its statutory responsibilities under the NGA. That there currently are a number of planned, proposed, or approved infrastructure projects to increase infrastructure capacity to transport natural gas from the Marcellus and Utica Shale does not establish that the Commission is engaged in regional development or planning.[386] Instead, this confirms that pipeline projects to transport

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[381] *See Piedmont Environmental Council v. FERC*, 558 F.3d 304, 316-17 (4th Cir. 2009) (*Piedmont Environmental Council*).

[382] *See, e.g., National Fuel Gas Supply Corp.*, 158 FERC ¶ 61,145 at PP 82-88; *National Fuel Gas Supply Corp.*, 154 FERC ¶ 61,180, at P 13 (2016); *Texas Eastern Transmission, LP*, 149 FERC ¶ 61,259, at PP 38-47 (2014); *Columbia Gas Transmission, LLC*, 149 FERC ¶ 61,255 (2014).

[383] 15 U.S.C. § 717f(e) (2012).

[384] 40 C.F.R. § 1508.25(a)(1)-(2) (2017) (defining connected and cumulative actions).

[385] *See, e.g.*, EA for the Monroe to Cornwell Project and the Utica Access Project, Docket Nos. CP15-7-000 & CP15-87-000 (filed Aug. 19, 2015); Final Multi-Project Environmental Impact Statement for Hydropower Licenses: Susquehanna River Hydroelectric Projects, Project Nos. 1888-030, 2355-018, and 405-106 (filed Mar. 11, 2015).

[386] *See, e.g., Sierra Club v. FERC*, 827 F.3d 36, 50 (D.C. Cir. 2016) (Freeport LNG) (rejecting claim that NEPA requires FERC to undertake a nationwide analysis of all applications for liquefied natural gas export facilities); *cf. Myersville Citizens for a*

Marcellus and Utica Shale gas are initiated solely by a number of different companies in private industry. As we have noted previously, a programmatic EIS is not required to evaluate the regional development of a resource by private industry if the development is not part of, or responsive to, a federal plan or program in that region.[387]

283. The Commission's siting decisions regarding pending and future natural gas pipeline facilities respond to proposals by private industry, and the Commission has no way to accurately predict the scale, timing, and location of projects, much less the kind of facilities that will be proposed.[388] Any broad, regional environmental analysis would "be little more than a study . . . containing estimates of potential development and attendant environmental consequences,"[389] and could not present "a credible forward look" that would be "a useful tool for basic program planning."[390] In these circumstances, the Commission's longstanding practice to conduct an environmental review for each proposed project, or a number of proposed projects that are interdependent or otherwise interrelated or connected, "facilitate[s], not impede[s], adequate environmental assessment."[391] Thus, the Commission's environmental review of the ACP and Supply Header projects together in a single EIS is appropriate under NEPA.

284. In sum, CEQ states that a programmatic EIS can "add value and efficiency to the decision-making process when they inform the scope of decisions," "facilitate decisions on agency actions that precede site- or project-specific decisions and actions," or

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Rural Cmty., Inc. v. FERC, 783 F.3d 1301, 1326-27 (D.C. Cir. 2015) (*Myersville*) (upholding FERC determination that, although a Dominion Transmission Inc.-owned pipeline project's excess capacity may be used to move gas to the Cove Point terminal for export, the projects are "unrelated" for purposes of NEPA).

[387] *See Kleppe*, 427 U.S. at 401-02 (holding that a regional EIS is not required where there is no overall plan for regional development).

[388] Lack of jurisdiction over an action does not necessarily preclude an agency from considering the potential impacts. As explained in the indirect and cumulative impact sections of this order, however, it reinforces our finding that because states, and not the Commission, have jurisdiction over natural gas production and associated development (including siting and permitting), the location, scale, timing, and potential impacts from such development are even more speculative.

[389] *Kleppe*, 427 U.S. at 402.

[390] *Piedmont Environmental Council*, 558 F.3d at 316.

[391] *Id.*

"provide information and analyses that can be incorporated by reference in future NEPA reviews."[392] The Commission does not believe these benefits can be realized by a programmatic review of natural gas infrastructure projects because the projects subject to our jurisdiction do not share sufficient elements in common to narrow future alternatives or expedite the current detailed assessment of each particular project. Thus we find a programmatic EIS is neither required nor useful under the circumstances here.

I. Indirect Impacts of Upstream and Downstream Activities

285. Interveners and commenters broadly argue that the EIS must consider the project's indirect effects, particularly regarding impacts of induced upstream production of natural gas from the Marcellus and Utica Shale. In addition they assert that the Commission must consider as indirect impacts the downstream end-use, of natural gas on greenhouse gases and climate change.

286. CEQ's regulations direct federal agencies to examine the direct, indirect, and cumulative impacts of proposed actions.[393] Indirect impacts are defined as those "which are caused by the action and are later in time or farther removed in distance, but are still reasonably foreseeable."[394] Further, indirect effects "may include growth inducing effects and other effects related to induced changes in the pattern of land use, population density or growth rate, and related effects on air and water and other natural systems, including ecosystems."[395] Accordingly, to determine whether an impact should be studied as an indirect impact, the Commission must determine whether it is both (1) caused by the proposed action; and (2) reasonably foreseeable.

287. With respect to causation, "NEPA requires 'a reasonably close causal relationship' between the environmental effect and the alleged cause"[396] in order "to make an agency responsible for a particular effect under NEPA."[397] As the Supreme Court explained, "a

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[392] 2014 Programmatic Guidance at 13.

[393] 40 C.F.R. § 1508.25(c) (2016).

[394] *Id.* § 1508.8(b).

[395] *Id.* § 1508.8(b).

[396] *U.S. Dep't of Transp. v. Pub. Citizen*, 541 U.S. 752, at 767 (2004) (*Pub. Citizen*) (quoting *Metropolitan Edison Co. v. People Against Nuclear Energy*, 460 U.S. 766, at 774 (1983) (*Metro Edison Co.*).

[397] *Id.*

'but for' causal relationship is insufficient [to establish cause for purposes of NEPA]."[398] Thus, "[s]ome effects that are 'caused by' a change in the physical environment in the sense of 'but for' causation," will not fall within NEPA if the causal chain is too attenuated.[399] Further, the Court has stated that "where an agency has no ability to prevent a certain effect due to its limited statutory authority over the relevant actions, the agency cannot be considered a legally relevant 'cause' of the effect."[400]

288. An effect is "reasonably foreseeable" if it is "sufficiently likely to occur that a person of ordinary prudence would take it into account in reaching a decision."[401] NEPA requires "reasonable forecasting," but an agency is not required "to engage in speculative analysis" or "to do the impractical, if not enough information is available to permit meaningful consideration."[402]

i. <u>Impacts from Upstream Natural Gas Production</u>

289. With respect to the argument that the Commission must analyze the environmental impacts associated with the upstream production of natural gas that may be induced by the approval of ACP and Supply Header projects, as we have previously concluded, the environmental effects resulting from natural gas production are generally neither caused by a proposed pipeline (or other natural gas infrastructure) project nor are they reasonably foreseeable consequences of our approval of an infrastructure project, as

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[398] *Id.*; *see also* Freeport LNG, 827 F.3d at 46 (FERC need not examine everything that could conceivably be a but-for cause of the project at issue); *Sierra Club v. FERC*, 827 F.3d 59, 68 (D.C. Cir. 2016) (Sabine Pass LNG) (FERC order authorizing construction of liquefied natural gas export facilities is not the legally relevant cause of increased production of natural gas).

[399] *Metro. Edison Co.*, 460 U.S. at 774.

[400] *Pub. Citizen*, 541 U.S. at 770; *see also* Freeport LNG, 827 F.3d at 49 (affirming that *Public Citizen* is explicit that FERC, in authorizing liquefied natural gas facilities, need not consider effects, including induced production, that could only occur after intervening action by the DOE); Sabine Pass LNG, 827 F.3d at 68 (same); *EarthReports, Inc. v. FERC*, 828 F.3d at 955-56 (same).

[401] *Sierra Club v. Marsh*, 976 F.2d 763, 767 (1st Cir. 1992). *See also City of Shoreacres v. Waterworth*, 420 F.3d 440, 453 (5th Cir. 2005).

[402] *N. Plains Res. Council, Inc. v. Surface Transp. Bd.*, 668 F.3d 1067, 1078 (9th Cir. 2011).

contemplated by CEQ regulations.[403] A causal relationship sufficient to warrant Commission analysis of the non-pipeline activity as an indirect impact would only exist if the proposed pipeline would transport new production from a specified production area and that production would not occur in the absence of the proposed pipeline (i.e., there will be no other way to move the gas).[404] To date, the Commission has not been presented with a proposed pipeline project that the record shows will cause the predictable development of gas reserves. In fact, the opposite causal relationship is more likely, i.e., once production begins in an area, shippers or end users will support the development of a pipeline to move the produced gas.

290. Even accepting, *arguendo*, that a specific pipeline project will cause natural gas production, we have found that the potential environmental impacts resulting from such production are not reasonably foreseeable. As we have explained, the Commission generally does not have sufficient information to determine the origin of the gas that will be transported on a pipeline. It is the states, rather than the Commission, that have jurisdiction over the production of natural gas and thus would be most likely to have the information necessary to reasonably foresee future production. There are no forecasts in the record which would enable the Commission to meaningfully predict production-related impacts, many of which are highly localized. Thus, even if the Commission knows the general source area of gas likely to be transported on a given pipeline, a meaningful analysis of production impacts would require more detailed information regarding the number, location, and timing of wells, roads, gathering lines, and other appurtenant facilities, as well as details about production methods, which can vary per producer and depending on the applicable regulations in the various states. Accordingly, the impacts of natural gas production are not reasonably foreseeable because they are "so nebulous" that we "cannot forecast [their] likely effects" in the

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[403] *See, e.g., Central New York Oil and Gas Co., LLC*, 137 FERC ¶ 61,121, at PP 81-101 (2011), *order on reh'g*, 138 FERC ¶ 61,104, at PP 33-49 (2012), *petition for review dismissed sub nom. Coal. for Responsible Growth v. FERC*, 485 F. Appx., 472, 474-75 (2nd. Cir. 2012) (unpublished opinion).

[404] *See cf. Sylvester v. U.S. Army Corps of Engineers*, 884 F.2d 394, 400 (9th Cir. 1989) (upholding the environmental review of a golf course that excluded the impacts of an adjoining resort complex project). *See also Morongo Band of Mission Indians v. FAA*, 161 F.3d 569, 580 (9th Cir. 1998) (concluding that increased air traffic resulting from airport plan was not an indirect, "growth-inducing" impact); *City of Carmel-by-the-Sea v. U.S. Dep't of Transportation.*, 123 F.3d 1142, 1162 (9th Cir. 1997) (acknowledging that existing development led to planned freeway, rather than the reverse, notwithstanding the project's potential to induce additional development).

context of an environmental analysis of the impacts related to a proposed interstate natural gas pipeline.[405]

291. Nonetheless, we note that the Department of Energy has examined the potential environmental impacts generally associated with unconventional natural gas production activities.[406] The DOE Addendum concludes that such production, when conforming to regulatory requirements, implementing best management practices, and administering pollution prevention concepts, may have temporary, minor impacts to water resources.[407] With respect to air quality, the Department of Energy found that natural gas development leads to both short- and long-term increases in local and regional air emissions.[408] It also found that such emissions may contribute to climate change.[409] But to the extent that natural gas production replaces the use of other carbon-based energy sources, the U.S.

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[405] *Habitat Education Center v. U.S. Forest Service*, 609 F.3d 897, 902 (7th Cir. 2010) (finding that impacts that cannot be described with enough specificity to make their consideration meaningful need not be included in the environmental analysis). *See also Sierra Club v. DOE*, 867 F.3d 189, 198-199 (D.C. Cir. 2017) (accepting DOE's "reasoned explanation" as to why the indirect effects pertaining to induced natural gas production were not reasonably foreseeable where DOE noted the difficulty of predicting the incremental quantity of natural gas that might be produced, where at the local level such production might occur, and that an economic model estimating localized impacts would be far too speculative to be useful).

[406] U.S. Department of Energy, *Addendum to Environmental Review Documents Concerning Exports of Natural Gas from the United States*, 79 Fed. Reg. 48,132 (Aug. 15, 2014) (DOE Addendum), available at http://energy.gov/sites/prod/files/2014/08/f18/Addendum.pdf (analyzing air quality, water resource, GHG emissions, induced seismicity, and land use impacts from unconventional natural gas production activities in the lower 48 states). The U.S. Court of Appeals for the D.C. Circuit has upheld DOE's reliance on the DOE Addendum to supplement its environmental review of the proposed export of LNG. *See Sierra Club v. DOE*, 867 F.3d at 195, 201.

[407] DOE Addendum at 19; *see also Oil and Gas; Hydraulic Fracturing on Federal and Indian Lands*, 80 Fed. Reg. 16,128, 16,130 (Mar. 26, 2015) (Bureau of Land Management promulgated regulations for hydraulic fracturing on federal and Indian lands to "provide significant benefits to all Americans by avoiding potential damages to water quality, the environment, and public health").

[408] DOE Addendum at 32.

[409] *Id.* at 44.

Department of Energy found that there may be a net positive impact in terms of climate change.[410] We find the information provided in the DOE Addendum to be helpful to generally inform the public regarding potential impacts of increased natural gas production and therefore consider the DOE Addendum to be supplemental material to our environmental review.

292. While the DOE Addendum provides a nation-wide impacts analysis, Commission staff estimated the impacts on land use and water consumption associated with the production wells that would be required to provide 100 percent of the volume of natural gas which could be transported by the ACP and Supply Header projects over the life of the projects[411] from the Marcellus and Utica Shale basin. Each natural gas well pad and associated infrastructure (road infrastructure, water impoundments, and pipelines) requires about 1.48 acres of land.[412] Based on the projects' volume and the expected estimated ultimate recovery of Marcellus/Utica Shale wells,[413] our Commission staff estimates that between 2,149 and 4,212 wells would be required to provide the gas over the estimated 30-year project lifespan. Therefore, on a normalized basis,[414] drilling wells may affect between 106 and 208 acres a year.[415] Previous research[416] indicates that, within the Marcellus and Utica Shale areas, about 72.3 percent of the land affected by natural gas production is forest, about 22.4 percent is agricultural, and about 5.3 percent is grass or open lands.

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[410] *Id.*

[411] Our environmental staff assumed a 30 year life of the project.

[412] Life Cycle Analysis of Natural Gas Extraction and Power Generation, Dept. of Energy and Nat'l Energy Tech. Laboratory DOE/NETL-2015/1714; page 22, Table 3-6, (August 30, 2016).

[413] Energy Information Assoc. http://www.eia.gov/conference/2015/pdf/presentations/staub.pdf, and Environmental Impacts of Unconventional Natural Gas Development and Production, DOE/NETL-2014/1651 (May 29, 2014).

[414] 30 year impacts averaged on a per year basis.

[415] Dept. of Energy and Nat'l Energy Tech. Laboratory, *Life Cycle Analysis of Natural Gas Extraction and Power Generation,* DOE/NETL-2015/1714, page 22, table 3-6 (August 30, 2016) .

[416] *Id.* at DOE/NETL-2015/1714, pg 24, table 3-8.

293. Recent estimates[417] show that drilling and developing an average Marcellus Shale well requires between 3.88 and 5.69 million gallons of water, depending on whether the producer uses a recycling process. Therefore, producing wells required to supply the project could require the normalized consumptive use of as much as 278 to 798 million gallons of water per year over the 30-year project life. In addition, staff conservatively estimated the upstream GHG emissions from extraction as 1.2 million metric tpy CO_{2e}, and from processing as 2.4 million metric tpy CO_{2e}.[418]

294. The record in this proceeding does not demonstrate the requisite reasonably close causal relationship between the impacts of future natural gas production and the proposed projects that would necessitate the specific local-level impacts analysis that commenters seek.[419] The fact that natural gas production and transportation facilities are all components of the general supply chain required to bring domestic natural gas to market is not in dispute. We have acknowledged that the pipeline projects are designed to move gas supplies from the Appalachian Basin to markets in Virginia and North Carolina. This does not mean, however, that approving these particular projects will induce further shale gas production. Rather, as we have explained in other proceedings, a number of factors,

[417] Environmental Impacts of Unconventional Natural Gas Development and Production May 29, 2014 DOE/NETL-2014/1651; page 76, exhibit 4-1.

[418] The upstream GHG emissions were estimated using the May 29, 2014 Life Cycle Analysis of Natural Gas Extraction and Power Generation May 29, 2014 DOE/NETL-2014/1646. Generally, Commission staff used the average leak and emission rates identified in the NETL analysis for each segment of extraction, processing, and transport. The method is outlined in Section 2 of the NETL report, and the background data used for the model is outlined in Section 3.1. Staff used the results identified in Tables 4.3, 4.4, and 4.5 to look at each segment and grossly estimate GHG emission. To be conservative, staff did not account for the New Source Performance Standards Oil & Gas rule changes, or other GHG mitigation. Additionally, staff made a conservative estimate of the length of non-jurisdictional pipeline prior to the gas reaching Project components, as well as the length of downstream pipeline to the delivery point. *See Sierra Club v. DOE*, 867 F.3d at 201-202 (finding sufficient DOE's estimate of potential GHG emissions from producing, transporting and exporting LNG reported in a 2014 Life Cycle Report on Exporting LNG).

[419] *See Sierra Club v. DOE*, 867 F.3d at 200 (rejecting contention that DOE must project shale-play level environmental impacts specific to the amount of liquefied natural gas exports it authorized).

such as domestic natural gas prices and production costs drive new drilling.[420] If the proposed projects were not constructed, it is reasonable to assume that any new production spurred by such factors would reach intended markets through alternate pipelines or other modes of transportation.[421] Again, any such production would take place pursuant to the regulatory authority of state and local governments.[422]

295. Moreover, even if a causal relationship between our action here and additional production were presumed, the scope of the impacts from any induced production is not reasonably foreseeable. That there may be incentives for producers to locate wells close to pipeline infrastructure does not change the fact that the location, scale, and timing of any additional wells are matters of speculation, particularly regarding their relationship to the proposed projects. As we have previously explained, a broad analysis, based on

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[420] *Rockies Express Pipeline LLC,* 150 FERC ¶ 61,161, at P 39 (2015). *See also Sierra Club v. DOE*, 867 F.3d at 198 (accepting DOE's explanation that natural gas production is driven by numerous factors including the price of gas, pace of technological change, and U.S. environmental regulations and that there is fundamental uncertainty about how natural gas production at the local level will respond to price changes at the national level); *Sierra Club v. Clinton*, 746 F. Supp. 2d 1025, 1045 (D. Minn. 2010) (holding that the U.S. Department of State, in its environmental analysis for an oil pipeline permit, properly decided not to assess the transboundary impacts associated with oil production because, among other things, oil production is driven by oil prices, concerns surrounding the global supply of oil, market potential, and cost of production); *Florida Wildlife Fed'n v. Goldschmidt*, 506 F. Supp. 350, 375 (S.D. Fla. 1981) (ruling that an agency properly considered indirect impacts when market demand, not a highway, would induce development).

[421] *Rockies Express Pipeline LLC,* 150 FERC ¶ 61,161 at P 39; *see also Sierra Club v. DOE*, 867 F.3d at 199 (noting that there is an interconnected pipeline system throughout the lower 48 states).

[422] We acknowledge that NEPA may obligate an agency to evaluate the environmental impacts of non-jurisdictional activities. That states, however, not the Commission, have jurisdiction over natural gas production and associated development (including siting and permitting) supports the conclusion that information about the scale, timing, and location of such development and potential environmental impacts are even more speculative. *See Sierra Club v. DOE*, 867 F.3d at 200 (DOE's obligation under NEPA to "drill down into increasingly speculative projections about regional environmental impacts [of induced natural gas production] is also limited by the fact that it lacks any authority to control the locale or amount of export-induced gas production, much less any of its harmful effects") (citing *Pub. Citizen*, 541 U.S. at 768).

generalized assumptions rather than reasonably specific information, will not provide meaningful assistance to the Commission in its decision making, e.g., evaluating potential alternatives to a specific proposal.[423]

ii. **Impacts from Downstream Combustion of Project-Transported Natural Gas**

296. Interveners and commenters also assert that the Commission must consider the impacts on climate change as a result of the end-use consumption of the natural gas transported by the pipeline.

297. With respect to impacts from GHGs, the final EIS discusses the direct GHG impacts from construction and operation of the projects and other projects that were considered in the Cumulative Impacts analysis, the climate change impacts in the region, and the regulatory structure for GHGs under the Clean Air Act. The final EIS also quantifies GHG emissions from the projects' construction (totaling 1,115,374 tons, CO_2-equivalent [CO_{2e}]) and operation (1,347,035 tons per year [tpy] CO_{2e}).[424]

298. In addition, Commission staff used an EPA-developed methodology to estimate the downstream GHG emissions resulting from the ultimate use of the gas transported on the ACP and Supply Header projects.[425] The final EIS includes a conservative estimate of downstream GHG emissions of 29.96 million tpy CO_{2e} from end-use combustion.[426] We note that this estimate represents an upper bound for the amount of end-use combustion that could result from the gas transported by these projects. This is because some of the gas may displace other fuels, which could actually lower total CO_{2e} emissions. It may also displace gas that otherwise would be transported via different means, resulting in no change in CO_{2e} emissions.

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[423] *Rockies Express Pipeline LLC,* 150 FERC ¶ 61,161 at P 40. *See also Sierra Club v DOE*, 867 F.3d at 198 (holding that the dividing line between what is reasonable forecasting and speculation is the "usefulness of any new potential information to the decision-making process").

[424] *See* final EIS at 4-556 through 4-559.

[425] Estimated using EPA's GHG Equivalencies Calculator - Calculations and References *available at* https://www.epa.gov/energy/ghg-equivalencies-calculator-calculations-and-references.

[426] Total annual emissions of GHG were estimated for ACP and Supply Header projects based on the total capacity of 1.5 billion cubic feet per day for the projects.

299. Sierra Club argues that because of the recent decision by the D.C. Circuit Court of Appeals in *Sierra Club v. FERC*[427] the Commission should reopen the record in this proceeding and issue a supplemental EIS to address GHG emissions and climate impacts. Sierra Club asserts that, although the final EIS did estimate the GHG emissions from combustion, the final EIS erroneously states that those emissions are not "causally connected" to the projects. To support its claim, Sierra Club cites Sabal Trail, in which the court stated that burning gas transported by pipeline "is not just 'reasonably foreseeable,' it is the project's entire purpose."[428]

300. Sierra Club claims that the final EIS was not only required to quantify the GHG emissions, but also must include a discussion of their significance and any cumulative impacts associated with GHG emissions. Sierra Club argues that the final EIS only provides a cursory analysis of the impact associated with downstream combustion, comparing the emissions to state-wide totals.[429] Sierra Club also states that the final EIS relies on the assertion that the projects would result in the displacement of some coal, but that this approach was rejected by the court in Sabal Trail because the Commission failed to assess whether total emissions would be reduced or increased, or what the degree of reduction or increase would be.[430]

301. Next, Sierra Club asserts that the final EIS should have used the social cost of carbon methodology to determine how the proposed project's incremental contribution to GHG emissions would translate into physical effects on the global environment. Sierra Club asserts that the court in Sabal Trail held that the Commission must explain why it did not use the methodology to determine project-specific impacts.[431]

302. Last, Sierra Club states that the final EIS's statement that "the emissions would increase the atmospheric concentration of GHGs, in combination with past and future emissions from all other sources, and contribute incrementally to climate change that produces the impacts previously described" does not adequately address the cumulative

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[427] *Sierra Club v. FERC*, 867 F.3d 1357 (D.C. Cir. 2017) (Sabal Trail).

[428] Sabal Trail, 867 F.3d at 1372.

[429] Sierra Club states that the final EIS states both "we cannot determine whether the projects' contribution to cumulative impacts on climate change would be significant," and that "we conclude that ACP and SHP would not significantly contribute to GHG cumulative impacts or climate change."

[430] *Sabal Trail*, 867 F.3d at 1374-75.

[431] *Id.* at 1375.

impacts of the projects. Sierra Club avers that the final EIS incorrectly downplays the cumulative climate impacts associated with the natural gas infrastructure build out in Pennsylvania, West Virginia, Virginia, North Carolina, and surrounding states, and does not quantify the project's GHG emissions in combination with these past, present, and reasonably foreseeable gas projects.

303. Sierra Club concludes that as a result of the final EIS's failure to address these concerns, the Commission did not conduct an informed public process and failed to provide information necessary to assess potential alternatives and mitigation measures.

304. The court in Sabal Trail held that where it is known that the natural gas transported by a project will be used for end-use combustion, the Commission should "estimate[] the amount of power-plant carbon emissions that the pipelines will make possible."[432] As Sierra Club acknowledges, the final EIS did just that. The fact that the final EIS stated that the emissions were not "causally connected" to the project is immaterial because the information was presented in both the draft and final EIS.[433] Thus, the Commission and the public were fully informed of the potential impacts from the project.

305. In an effort to provide some context to the GHG emissions from the ACP and Supply Header projects, the final EIS included the GHG inventory for Pennsylvania, West Virginia, Virginia, and North Carolina.[434] Table 1 compares the GHG emissions from the project to the GHG Inventories for the four-state region and nationwide. Table 1 includes two scenarios: (1) all natural gas transported by the projects is used for end-use combustion (full burn) and (2) 79 percent of the natural gas transported by project is used for power generation (estimate of actual consumption).[435]

Table 1		
	Estimate of Actual Consumption Emissions	**Full Burn Emissions**
GHG Volume	23.67	29.96

[432] *Id.* at 1371.

[433] Final EIS at 4-620; Draft EIS at 4-512 through 4-513.

[434] Final EIS at 4-620.

[435] Atlantic anticipates approximately 79.2 percent of the natural gas transported by project would be used as a fuel to generate electricity for industrial, commercial, and residential uses. *Id.* at 1-3.

(Million Metric tons per year)		
Percentage of Four State Inventory	4.12	5.2
Percentage of National Inventory	0.44	0.56

Thus, we estimate that the downstream use of the natural gas to be transported by the projects would potentially increase the GHG emissions inventory in the four-state region by up to 5.2 percent.

306. Moreover, the final EIS acknowledged that the emissions would increase the atmospheric concentration of GHGs, in combination with past and future emissions from all other sources, and contribute incrementally to climate change.[436] However, as the final EIS explained, because the project's incremental physical impacts on the environment caused by climate change cannot be determined, it also cannot be determined whether the projects' contribution to cumulative impacts on climate change would be significant.[437]

307. We also disagree with Sierra Club's assertion that the Commission should have used the social cost of carbon methodology to determine how the proposed projects' incremental contribution to GHGs would translate into physical effects on the global environment. While we recognize the availability of the social cost of carbon methodology, it is not appropriate for use in any project-level NEPA review for the following reasons: (1) EPA states that "no consensus exists on the appropriate [discount]

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[436] *Id.* at 4-620.

[437] *Id.*

rate to use for analyses spanning multiple generations"[438] and consequently, significant variation in output can result;[439] (2) the tool does not measure the actual incremental impacts of a project on the environment; and (3) there are no established criteria identifying the monetized values that are to be considered significant for NEPA reviews. The methodology may be useful for rulemakings or comparing regulatory alternatives using cost-benefit analyses where the same discount rate is consistently applied; however, it is not appropriate for estimating a specific project's impacts or informing our analysis under NEPA. Moreover, Executive Order 13783, Promoting Energy Independence and Economic Growth, has disbanded the Interagency Working Group on Social Cost of Greenhouse Gases and directed the withdrawal of all technical support documents and instructions regarding the methodology, stating that the documents are "no longer representative of governmental policy."[440]

m. Cumulative Impacts

308. A number of commenters raised issues related to the cumulative impacts of the projects. CEQ defines "cumulative impact" as "the impact on the environment which results from the incremental impact of the action [being studied] when added to other past, present, and reasonably foreseeable future actions . . . ."[441] The requirement that an impact must be "reasonably foreseeable" to be considered in a NEPA analysis applies to both indirect and cumulative impacts.

309. The "determination of the extent and effect of [cumulative impacts], and particularly identification of the geographic area within which they may occur, is a task assigned to the special competency of the appropriate agencies."[442] CEQ has explained that "it is not practical to analyze the cumulative effects of an action on the universe; the list of environmental effects must focus on those that are truly meaningful."[443] Further, a

[438] *See* Fact Sheet: Social Cost of Carbon issued by EPA in November 2013, http://www.epa.gov/climatechange/Downloads/EPAactivities/scc-fact-sheet.pdf.

[439] Depending on the selected discount rate, the tool can project widely different present day cost to avoid future climate change impacts.

[440] Exec. Order No. 13783, 82 Fed. Reg. 16093 (Mar. 28, 2017).

[441] 40 C.F.R. § 1508.7 (2017).

[442] *Kleppe*, 427 U.S. at 413.

[443] CEQ, *Considering Cumulative Effects Under the National Environmental Policy Act* at 8 (January1997) (1997 Cumulative Effects Guidance).

cumulative impact analysis need only include "such information as appears to be reasonably necessary under the circumstances for evaluation of the project rather than to be so all-encompassing in scope that the task of preparing it would become either fruitless or well-nigh impossible."[444] An agency's analysis should be proportional to the magnitude of the environmental impacts of a proposed action; actions that will have no significant direct and indirect impacts usually require only a limited cumulative impacts analysis.[445]

310. In considering cumulative impacts, CEQ advises that an agency first identify the significant cumulative effects issues associated with the proposed action.[446] The agency should then establish the geographic scope for analysis. Next, the agency should establish the time frame for analysis.[447] Finally, the agency should identify other actions that potentially affect the same resources, ecosystems, and human communities that are affected by the proposed action.[448] As noted above, CEQ advises that an agency should relate the scope of its analysis to the magnitude of the environmental impacts of the proposed action.[449]

311. Commission staff defined the geographic scope for its analysis of cumulative impacts on specific environmental resources to include projects/actions within the same construction footprint as the projects for geology, soils, and land use; within the U.S. Geological Survey hydrologic unit code 10 watersheds for water resources, wetlands, vegetation, aquatic resources, wildlife, and reliability and safety; within 0.5 mile of the projects for visual resources, with an additional 5-mile visual radius around each compressor station; at the county level for socioeconomic impacts; within 0.5 mile of the projects for NSAs around compressor stations; within the area of potential effect for cultural resources; within the Air Quality Control Regions for climate change; and for air quality impacts, within 0.5 mile of the project for construction impacts and within the Air Quality Control Regions for operational impacts.

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[444] *Id.*

[445] *See* CEQ, *Memorandum on Guidance on Consideration of Past Actions in Cumulative Effects Analysis* at 2-3 (June 24, 2005).

[446] 1997 Cumulative Effects Guidance at 11.

[447] *Id.*

[448] *Id.*

[449] CEQ, *Memorandum on Guidance on Consideration of Past Actions in Cumulative Effects Analysis* at 2 (June 24, 2005).

312. The types of other projects, in addition to the ACP and Supply Header projects, evaluated in the final EIS within the same geographic region and appropriate time frame that could potentially contribute to cumulative impacts on a range of environmental resources include other Commission-jurisdictional natural gas interstate transportation projects; non-jurisdictional pipelines and gathering system projects; oil and gas exploration and production activities; mining operations; transportation or road projects; commercial/residential/industrial and other development projects; and other energy projects, including power plants or electric transmission lines.

313. The final EIS concludes that most cumulative impacts would be temporary and minor when considered in combination with past, present, and reasonably foreseeable activities. Long-term but minor cumulative impacts would occur on wetland, upland forested vegetation, and associated wildlife habitats, as well as waterbodies, special status species, and visual quality. Impacts on vernal pools, rocky outcrops, and subterranean features could adversely affect habitat of wildlife species with limited mobility and home ranges. Subterranean obligate species are often endemic to only a few known locations, and are vulnerable to changes in hydrological pattern or water quality;[450] therefore, it is possible that impacts associated with construction activities could have population-level impacts on these species. Short-term cumulative benefits will also be realized through jobs and wages and purchases of goods and materials. There is also the potential that the projects will contribute to a cumulative improvement in regional air quality if a portion of the natural gas associated with the proposed projects displaces the use of other, more polluting fossil fuels.[451]

n. Alternatives

314. The final EIS analyzes alternatives, including the no action alternative, system alternatives, and route alternatives. If the no action alternative is selected, the environmental impacts outlined in the final EIS will not occur. However, if the projects are not authorized, their stated objectives will not be realized, and natural gas will not be transported from production areas in the Appalachian Basin to end-users in Virginia and North Carolina. In response to the no active alternative, shippers may seek other infrastructure to transport natural gas to customers, and construction of those other projects may result in environmental impacts that will be similar to or greater than the proposed projects.

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[450] West Virginia Division of Natural Resources, 2015 West Virginia State Wildlife Action Plan (Sep. 1, 2015), http://www.wvdnr.gov/2015%20West%20Virginia%20State%20Wildlife%20Action%20Plan%20Submittal.pdf.

[451] Final EIS at 4-623.

315. The final EIS also considers if the contracted volumes of the ACP and Supply Header projects could be transported through the Mountain Valley Project and Equitrans Expansion Project (collectively, the Mountain Valley Project) proposed in Docket Nos. CP16-10-000 and CP16-13-000, respectively. The EIS examines two hypothetical scenarios[452] for this: (1) the merged system alternative, in which the ACP and Supply Header projects' volumes would be transported together with the Mountain Valley Project volumes in a single pipeline along the proposed Mountain Valley Project route; and (2) the collocation alternative, in which the ACP Project pipeline would be relocated along the same route as the Mountain Valley Project, with additional pipeline to meet Atlantic's delivery requirements.

316. With respect to the collocation alternative, as described in the final EIS, there is insufficient space along the narrow ridgelines to accommodate two parallel 42-inch-diameter pipelines, making this alternative technically infeasible.[453] Construction of such pipelines would require side-hill or two-tone construction techniques, with additional acres of disturbance required for additional temporary workspace, given the space needed to safely accommodate equipment and personnel, as well as spoil storage. The final EIS concludes, and we agree, that when the environmental factors, technical feasibility, and ability to meet the purpose and need of the projects are cumulatively considered, the collocation alternative does not offer a significant advantage.[454]

317. With respect to the merged system alternative, if the volumes of both the Mountain Valley Project and ACP Project, totaling about 3.44 billion cubic feet per day, were combined into a single 42-inch-diameater pipeline, the significant additional compression needed for such a project would restrict Atlantic's ability to provide operational flexibility for customers' potentially needed flow rate variations and line pack, and may prohibit any future expansion of the pipeline system. Commission staff

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[452] We note that no applicant has proposed to construct, and no shipper indicated an interest in utilizing either of the hypothetical alternative pipeline systems.

[453] *See* Final EIS at 3-9. *See also Fuel Safe Washington v. FERC*, 389 F.3d 1313, 1323 (10th Cir. 2004) (The Commission need not analyze "the environmental consequences of alternatives it has in good faith rejected as too remote, speculative, or ... impractical or ineffective.") (quoting *All Indian Pueblo Council v. United States*, 975 F.2d 1437, 1444 (10th Cir.1992) (internal quotation marks omitted)); *see also Nat'l Wildlife Fed'n v. F.E.R.C.*, 912 F.2d 1471, 1485 (D.C. Cir. 1990) (NEPA does not require detailed discussion of the environmental effects of remote and speculative alternatives); *Natural Resources Defense Council, Inc. v. Morton*, 458 F.2d 827, 837–38 (D.C.Cir.1972) (same).

[454] Final EIS at 3-11.

estimated that the necessary additional compression could triple air quality impacts in comparison to the Mountain Valley Project and ACP Project considered individually. Construction of larger diameter, non-typical 48-inch diameter pipeline would require a wider construction right-of-way.[455] Although, as the final EIS notes, the merged system alternative may hold an environmental advantage,[456] because this alternative may negatively impact shippers by reduced operational flexibility and future expansibility, the Commission finds that this alternative is not preferable.[457]

318. We are mindful, as the D.C. Circuit has acknowledged, that "given the choice, almost no one would want natural gas infrastructure built on their block."[458] But as the court noted:

> [G]iven our nation's increasing demand for natural gas . . . it is an inescapable fact that such facilities must be built somewhere. .... Congress decided to vest the [Commission] with responsibility for overseeing the construction and expansion of interstate natural gas facilities. And in carrying out that charge, sometimes the Commission is faced with tough judgment calls as to where those facilities can and should be sited.[459]

319. While "the existence of a more desirable alternative is one of the factors which enters into a determination of whether a particular proposal would serve the public convenience and necessity,"[460] we conclude, based on record evidence, that when

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[455] Final EIS at 3-10 (installation of 48-inch pipeline would require 30 feet or more of additional construction right-of-way over entire length of the pipeline route and would displace about 30 percent more soil).

[456] Final EIS at 3-9. We note that since no entity has proposed or engineered this hypothetical alternative, our assessments of potential benefits and impacts is necessarily limited, and based on best available information.

[457] *Midcoast Interstate Transmission, Inc. v. FERC*, 198 F.3d 960, 967-68 (D.C. Cir. 2000) (FERC must carefully consider alternatives, but even in the face of a preferable alternative, FERC may reasonably find that the proposed project is in the public convenience and necessity).

[458] *Minisink Residents for Environmental Preservation and Safety v. FERC*, 762 F.3d 97, 100 (D.C. Cir. 2014) (affirming the Commission's decision to approve project where two dissenting commissioners preferred an alternative pipeline project).

[459] *Id.*

[460] *City of Pittsburgh v. FPC*, 237 F.2d 741, 751 n.28 (D.C. Cir. 1956).

considering the environmental factors, technical feasibility, and ability to meet the purpose and need of the projects, including the time frames in which service has been requested by the shippers, these alternatives do not provide an advantage over the ACP and Supply Header projects.[461]

320. The final EIS also considered 26 other major route alternatives, 3 route variations along the ACP Project route, and 1 route variation along the Supply Header Project route. In almost all cases, the alternative routes were found to not provide a significant environmental advantage over the proposed route segments and were not recommended, with the exception of the Butterwood Creek Route Variation, a minor alignment shift that would reduce the number of stream crossings. We agree with the conclusions in the final EIS.

321. A number of commenters suggested that additional crossing locations be considered for the HDD of the Blue Ridge Parkway and Appalachian National Scenic Trail. In response, the final EIS considered several alternatives in the vicinity of the Rockfish Gap that would relocate the Blue Ridge Parkway and Appalachian National Scenic Trail HDD as well as modify the sections of the pipeline project to accommodate the shift in the crossing location. The final EIS concluded, based on a variety of factors, that relocating the HDD to the Rockfish gap could encounter difficulties based on constraints in the area including steep topography, structures, roads, bridges, a railroad tunnel, and limited locations for workspace outside of National Park Service lands and workspace necessary to fabricate the pull-back section of pipe, and ultimately may be infeasible.[462]

322. In addition, the Rockfish Gap alternatives identified by commenters involved collocating with existing roadways. The final EIS analyzed these alternatives and noted that roadways had been carved into the mountainside such that the alternative would involve extreme side-slope construction (i.e., significant grading, large workspaces, and large spoil staging areas). Furthermore, residential and commercial development along highways in the area would prevent the installation of a 42-inch-diameter pipeline in many areas. Therefore, the alternative routes would have to be modified in many areas to avoid construction constraints, which reduces the collocation advantages that this route could offer. Therefore, the final EIS concluded and we agree that the Rockfish Gap

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[461] The Commission's NEPA obligation requires that it "'identify the reasonable alternatives to the contemplated action' and 'look hard at the environmental effects of [its] decision[ ].'" *Midcoast Interstate Transmission, Inc. v. FERC*, 198 F.3d 960, 967 (D.C. Cir. 2000) (quoting *Corridor H Alternatives, Inc. v. Slater*, 166 F.3d 368, 374 (D.C.Cir.1999)) (alterations in original).

[462] Final EIS at 3-30.

Alternatives did not offer a significant environmental advantage and not requiring their adoption into the project.[463]

4. Environmental Analysis Conclusion

323. We have reviewed the information and analysis contained in the final EIS regarding potential environmental effects of the ACP Project, Supply Header Project, and the Capacity Lease, as well as the other information in the record. We are accepting the environmental recommendations in the final EIS as modified herein, and are including them as conditions in Appendix A to this order.

324. Any state or local permits issued with respect to the jurisdictional facilities authorized herein must be consistent with the conditions of this order. The Commission encourages cooperation between interstate pipelines and local authorities. However, this does not mean that state and local agencies, through application of state or local laws, may prohibit or unreasonably delay the construction or operation of facilities approved by this Commission.[464]

325. Based on our consideration of this information and the discussion above, we agree with the conclusions presented in the final EIS and find that the projects, if constructed and operated as described in the final EIS, are environmentally acceptable actions. Therefore, for the reasons discuss above, we find that the projects are in the public convenience and necessity.

326. The Commission on its own motion received and made a part of the record in this proceeding all evidence, including the applications, and exhibits thereto, and all comments and upon consideration of the record,

The Commission orders:

(A) A certificate of public convenience and necessity is issued authorizing

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[463] *Id.*

[464] *See* 15 U.S.C. § 717r(d) (state or federal agency's failure to act on a permit considered to be inconsistent with Federal law); *see also Schneidewind v. ANR Pipeline Co.*, 485 U.S. 293, 310 (1988) (state regulation that interferes with FERC's regulatory authority over the transportation of natural gas is preempted) and *Dominion Transmission, Inc. v. Summers,* 723 F.3d 238, 245 (D.C. Cir. 2013) (noting that state and local regulation is preempted by the NGA to the extent it conflicts with federal regulation, or would delay the construction and operation of facilities approved by the Commission).

Atlantic to construct and operate the Atlantic Coast Pipeline Project, as described in this order and in the applications in Docket Nos. CP15-554-000 and CP15-554-001.

(B) A certificate of public convenience and necessity is issued authorizing DETI to construct and operate the Supply Header Project, as described in this order and in the application in Docket No. CP15-555-000.

(C) A blanket transportation certificate is issued to Atlantic under Subpart G of Part 284 of the Commission's regulations.

(D) A blanket construction certificate is issued to Atlantic under Subpart F of Part 157 of the Commission's regulations.

(E) The certificate authority issued in Ordering Paragraph (A) and (B) shall be conditioned on the following:

> (1) Applicants' completion of the authorized construction of the proposed facilities and making them available for service within three years from the date of this order, pursuant to section 157.20(b) of the Commission's regulations;
>
> (2) Applicants' compliance with all applicable Commission regulations under the NGA including, but not limited to, Parts 154 and 284, and paragraphs (a), (c), (e), and (f) of section 157.20 of the regulations;
>
> (3) Applicants' compliance with the environmental conditions listed in Appendix A to this order.

(F) A certificate of public convenience and necessity is issued to Atlantic authorizing it to lease the subject capacity from Piedmont as described herein.

(G) A limited-jurisdiction certificate of public convenience and necessity is issued to Piedmont to operate 100,000 Dth per day of capacity on its North Carolina intrastate pipeline system for Atlantic.

(H) Atlantic shall notify the Commission within 10 days of the date of the acquisition of the capacity leased from Piedmont.

(I) DETI is authorized to abandon Compressor Units 1 and 2 at the Hastings Compressor Station in Wetzel County, West Virginia.

(J) DETI shall notify the Commission within 10 days of the date of the abandonment of the compressor units.

(K) Atlantic and DETI shall file a written statement affirming that they have executed firm contracts for the capacity levels and terms of service represented in signed precedent agreements, prior to commencing construction.

(L) Atlantic's initial rates and tariff are approved, as conditioned and modified above.

(M) Atlantic is required to file actual tariff records reflecting the initial rates and tariff language that comply with the requirements contained in the body of this order not less than 30 days and not more than 60 days prior to the commencement of interstate service consistent with Part 154 of the Commission's regulations.

(N) Atlantic and DETI must file not less than 60 days before the in-service date of the proposed facilities an executed copy of the non-conforming agreements reflecting the non-conforming language and a tariff record identifying these agreements as non-conforming agreements consistent with section 154.112 of the Commission's regulations.

(O) No later than three months after the end of its first three years of actual operation, as discussed herein, Atlantic must make a filing to justify its existing cost-based firm and interruptible recourse rates. Atlantic's cost and revenue study should be filed through the eTariff portal using a Type of Filing Code 580. In addition, Atlantic is advised to include as part of the eFiling description, a reference to Docket No. CP15-554-000 and the cost and revenue study.

(P) DETI's request for authority to charge an incremental reservation rate for the Supply Header Project is approved.

(Q) DETI shall file actual tariff records setting forth its incremental rates at least 30 days, but no more than 60 days, prior to the date the project facilities go into service. That filing should be made as an eTariff compliance filing using type of filing code 580, and will be assigned an RP docket. It will be processed separately from the instant certificate proceeding in Docket No. CP15-555-000.

(R) DETI's request to use its system-wide fuel retention percentage as well as its EPCA and TCRA surcharges is approved.

(S) DETI shall keep separate books and accounting of costs and revenues attributable to the Supply Header Project, as more fully described above.

(T) Atlantic shall adhere to the accounting requirements discussed in the body of this order.

(U) Atlantic and DETI shall notify the Commission's environmental staff by telephone or facsimile of any environmental noncompliance identified by other federal, state, or local agencies on the same day that such agency notifies Atlantic or DETI. The Applicants shall file written confirmation of such notification with the Secretary of the Commission within 24 hours.

(V) The requests for a trial-type hearing are denied.

By the Commission. Commissioner LaFleur is dissenting with a separate statement attached.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Appendix A
Environmental Conditions

As recommended in the final environmental impact statement (EIS) and otherwise amended herein, this authorization includes the following conditions. The section number in parentheses at the end of a condition corresponds to the section number in which the measure and related resource impact analysis appears in the final EIS.

These measures will further mitigate the environmental impact associated with construction and operation of the projects. We have included several conditions that require the applicants to file additional information **with their Implementation Plan** or **prior to construction**. Other conditions require actions **during operations**. Some are standard conditions typically attached to Commission Orders. There are conditions that apply to both applicants, and other conditions are specific to either Atlantic Coast Pipeline, LLC (Atlantic) or Dominion Energy Transmission, Inc. (DETI).

Conditions 1 through 12 are standard conditions that apply to both Atlantic and DETI.

1. Atlantic and DETI shall follow the construction procedures and mitigation measures described in their applications and supplements (including responses to staff data requests) and as identified in the EIS, unless modified by the Order. Atlantic and DETI must:

    a. request any modification to these procedures, measures, or conditions in a filing with the Secretary of the Commission (Secretary);

    b. justify each modification relative to site-specific conditions;

    c. explain how that modification provides an equal or greater level of environmental protection than the original measure; and

    d. receive approval in writing from the Director of the Office of Energy Projects (OEP) **before using that modification.**

2. The Director of OEP, or the Director's designee, has delegated authority to address any requests for approvals or authorizations necessary to carry out the conditions of the order, and take whatever steps are necessary to ensure the protection of all environmental resources during construction and operation of the projects. This authority shall allow:

    a. The modification of conditions of this order;

b. stop work authority; and

c. the imposition of additional measures deemed necessary to assure continued compliance with the intent of the conditions of the order as well as the avoidance or mitigation of unforeseen adverse environmental impacts resulting from project construction and operation.

3. **Prior to any construction**, Atlantic and DETI shall file affirmative statements with the Secretary, certified by senior company officials, that all company personnel, Environmental Inspectors (EIs), and contractor personnel would be informed of the EIs' authority and have been or would be trained on the implementation of the environmental mitigation measures appropriate to their jobs **before** becoming involved with construction and restoration activities.

4. The authorized facility locations shall be as shown in the EIS, as supplemented by filed alignment sheets, and shall include the staff's recommended Butterwood Creek Route Variation and workspace modifications identified in the EIS. **As soon as they are available, and before the start of construction**, Atlantic and DETI shall file with the Secretary any revised detailed survey alignment maps/sheets at a scale not smaller than 1:6,000 with station positions for all facilities approved by the Order. All requests for modifications of environmental conditions of the Order or site-specific clearances must be written and must reference locations designated on these alignment maps/sheets.

Atlantic's and DETI's exercise of eminent domain authority granted under the Natural Gas Act (NGA) section 7(h) in any condemnation proceedings related to the Order must be consistent with these authorized facilities and locations. Atlantic's and DETI's rights of eminent domain granted under NGA section 7(h) do not authorize them to increase the size of their natural gas facilities to accommodate future needs or to acquire a right-of-way for a pipeline to transport a commodity other than natural gas

5. Atlantic and DETI shall file with the Secretary detailed alignment maps/sheets and aerial photographs at a scale not smaller than 1:6,000 identifying all route realignments or facility relocations; staging areas; pipe storage yards; new access roads; and other areas that would be used or disturbed and have not been previously identified in filings with the Secretary. Approval for each of these areas must be explicitly requested in writing. For each area, the request must include a description of the existing land use/cover type, documentation of landowner approval, whether any cultural resources or federally listed threatened or endangered species would be affected, and whether any other environmentally sensitive areas are within or abutting the area. All areas shall be clearly identified

on the maps/sheets/aerial photographs. Each area must be approved in writing by the Director of OEP **before construction in or near that area.**

This requirement does not apply to extra workspace allowed by the FERC *Upland Erosion Control, Revegetation and Maintenance Plan* (Plan) and/or minor field realignments per landowner needs and requirements that do not affect other landowners or sensitive environmental areas such as wetlands.

Examples of alterations requiring approval include all route realignments and facility location changes resulting from:

a. implementation of cultural resources mitigation measures;

b. implementation of endangered, threatened, or special concern species mitigation measures;

c. recommendations by state regulatory authorities; and

d. agreements with individual landowners that affect other landowners or could affect sensitive environmental areas.

6. **At least 45 days prior to construction**, Atlantic and DETI shall file their respective Implementation Plans with the Secretary, for review and written approval by the Director of OEP. Atlantic and DETI must file revisions to their plans as schedules change. The plans shall identify:

a. how Atlantic and DETI would implement the construction procedures and mitigation measures described in its application and supplements (including responses to staff data requests), identified in the EIS, and required by the Order;

b. how Atlantic and DETI would incorporate these requirements into the contract bid documents, construction contracts (especially penalty clauses and specifications), and construction drawings so that the mitigation required at each site is clear to on-site construction and inspection personnel;

c. the number of EIs assigned per spread and how the company would ensure that sufficient personnel are available to implement the environmental mitigation;

d. the number of company personnel, including EIs and contractors, who would receive copies of the appropriate material;

e. the location and dates of the environmental compliance training and instructions Atlantic and DETI would give to all personnel involved with construction and restoration (initial and refresher training as the projects progress and personnel change), with the opportunity for OEP staff to participate in the training session(s);

f. the company personnel (if known) and specific portion of Atlantic's and DETI's organizations having responsibility for compliance;

g. the procedures (including use of contract penalties) Atlantic and DETI would follow if noncompliance occurs; and

h. for each discrete facility, a Gantt or PERT chart (or similar project scheduling diagram) and dates for:

   i. the completion of all required surveys and reports;

   ii. the environmental compliance training of on-site personnel;

   iii. the start of construction; and

   iv. the start and completion of restoration.

7. Atlantic and DETI shall employ a team of EIs (i.e., two or more or as may be established by the Director of OEP) per construction spread. The EI(s) shall be:

a. responsible for monitoring and ensuring compliance with all mitigation measures required by the Order and other grants, permits, certificates, or other authorizing documents;

b. responsible for evaluating the construction contractor's implementation of the environmental mitigation measures required in the contract (see condition 6 above) and any other authorizing document;

c. empowered to order correction of acts that violate the environmental conditions of the Order, and any other authorizing document;

d. a full-time position, separate from all other activity inspectors;

e. responsible for documenting compliance with the environmental conditions of the Order, as well as any environmental conditions/permit requirements imposed by other federal, state, or local agencies; and

f. responsible for maintaining status reports.

8. **Beginning with the filing of the Implementation Plans**, Atlantic and DETI shall each file updated status reports with the Secretary on a weekly basis until all construction and restoration activities are complete. On request, these status reports would also be provided to other federal and state agencies with permitting responsibilities. Status reports shall include:

   a. an update on Atlantic's and DETI's efforts to obtain the necessary federal authorizations;

   b. the construction status of each spread, work planned for the following reporting period, and any schedule changes for stream crossings or work in other environmentally sensitive areas;

   c. a listing of all problems encountered and each instance of noncompliance observed by the EIs during the reporting period (both for the conditions imposed by the Commission and any environmental conditions/permit requirements imposed by other federal, state, or local agencies);

   d. a description of the corrective actions implemented in response to all instances of noncompliance, and their cost;

   e. the effectiveness of all corrective actions implemented;

   f. a description of any landowner/resident complaints that may relate to compliance with the requirements of the Order, and the measures taken to satisfy their concerns; and

   g. copies of any correspondence received by Atlantic and DETI from other federal, state, or local permitting agencies concerning instances of noncompliance, and Atlantic's and DETI's responses.

9. Atlantic and DETI shall develop and implement an environmental complaint resolution procedure. The procedure shall provide landowners with clear and simple directions for identifying and resolving their environmental mitigation problems/concerns during construction of the ACP and Supply Header projects and restoration of the right-of-way. **Prior to construction**, Atlantic and DETI shall each mail the complaint procedures to each landowner whose property would be crossed by the ACP Project and Supply Header Project.

a. In its letter to affected landowners, Atlantic and DETI shall:

i. provide a local contact that the landowners should call first with their concerns; the letter should indicate how soon a landowner should expect a response;

ii. instruct the landowners that if they are not satisfied with the response, they should call Atlantic's and DETI's Hotline; the letter should indicate how soon to expect a response; and

iii. instruct the landowners that if they are still not satisfied with the response from Atlantic's and DETI's Hotline, they should contact the Commission's Landowner Helpline at 877-337-2237 or at LandownerHelp@ferc.gov.

b. In addition, Atlantic and DETI shall include in their respective weekly status report a copy of a table that contains the following information for each problem/concern:

i. the identity of the caller and date of the call;

ii. the location by milepost and identification number from the authorized alignment sheet(s) of the affected property;

iii. a description of the problem/concern; and

iv. an explanation of how and when the problem was resolved, would be resolved, or why it has not been resolved.

10. Atlantic and DETI must receive written authorization from the Director of OEP **before commencing construction of any project facilities**. To obtain such authorization, Atlantic and DETI must file with the Secretary documentation that it has received all applicable authorizations required under federal law (or evidence of waiver thereof). The Director of OEP will not issue a notice to proceed with construction of the Atlantic or DETI project facilities independently.

11. Atlantic and DETI must receive written authorization from the Director of OEP **before placing their respective projects into service**. Such authorization would only be granted following a determination that rehabilitation and restoration of the right-of-way and other areas affected by the ACP and Supply Header projects are proceeding satisfactorily.

12. **Within 30 days of placing the authorized facilities in service**, Atlantic and DETI shall file affirmative statements with the Secretary, certified by a senior company official:

    a. that the facilities have been constructed in compliance with all applicable conditions, and that continuing activities would be consistent with all applicable conditions; or

    b. identifying which of the Certificate conditions the applicant has complied with or would comply with. This statement shall also identify any areas affected by their respective projects where compliance measures were not properly implemented, if not previously identified in filed status reports, and the reason for noncompliance.

Condition 13 applies to Atlantic and shall be implemented <u>upon issuance of this Order</u> and <u>during operation of the facilities.</u>

13. Atlantic shall not exercise eminent domain authority granted under section 7(h) of the NGA to acquire a permanent pipeline right-of-way exceeding 50 feet in width. In addition, where Atlantic has obtained a larger permanent right-of-way width through landowner negotiations, routine vegetation mowing and clearing over the permanent right-of-way shall not exceed 50 feet in width. *(Section 2.2.1.1)*

Conditions 14 through 25 apply to both Atlantic and DETI, and shall be addressed <u>as part of Atlantic's and DETI's Implementation Plan</u>

14. Atlantic and DETI shall design all workspaces that are not identified in table 2.3.1-2 of the EIS to comply with the FERC Procedures. Any additional modifications to the FERC Procedures must be requested and justified in **Atlantic's and DETI's Implementation Plans**. *(Section 2.3.1.1)*

15. **As part of Atlantic's and DETI's Implementation Plans and prior to receiving written authorization from the Director of the OEP to commence construction of any project facilities**, Atlantic and DETI shall file with the Secretary environmental constraints maps illustrating the avoidance and conservation measures required by the resource agencies and committed to by Atlantic and DETI along the ACP Project and Supply Header Project routes. The environmental constraints maps can be provided in the form of alignment sheets with a separate environmental constraints band. *(Section 2.4)*

16. **As part of their Implementation Plans**, Atlantic and DETI shall file with the Secretary, for review and written approval by the Director of OEP, a *Plan for Discovery of Unanticipated Paleontological Resources* that describes how Atlantic

and DETI will recognize and manage significant fossils encountered during construction. This plan shall also describe the notification procedures to the appropriate authorities in each state crossed by the ACP and Supply Header projects. *(Section 4.1.5)*

17. **As part of their Implementation Plans**, Atlantic and DETI shall file with the Secretary, for review and written approval by the Director of OEP, proposed or potential sources of water used for dust control, anticipated quantities of water to be appropriated from each source, and the measures it will implement to ensure water sources and any related aquatic biota are not adversely affected by the appropriation activity. *(Section 4.3.2.7)*

18. **As part of their Implementation Plans**, Atlantic and DETI shall file with the Secretary and appropriate federal and state agencies an updated *Restoration and Rehabilitation Plan* and *Invasive Species Management Plan*, for review and written approval by the Director of OEP, that includes the following measures:

    a. aerial spraying will not be utilized for invasive species control along the right-of-way;

    b. no herbicides will be applied within 25 feet of Endangered Species Act (ESA)-listed plant species;

    c. no use of herbicides or pesticides within 100 feet of a waterbody or wetland, except where allowed by state or federal agencies;

    d. no spraying of insecticides or herbicides will be allowed within the 300-foot karst feature buffer, except where allowed by state or federal agencies; and

    e. includes the results of the West Virginia and Virginia Natural Heritage Program recommendations for herbicide treatment adjacent to sensitive features. *(Section 4.4.4)*

19. **As part of their Implementation Plans**, Atlantic and DETI shall file with the Secretary, a revised *Migratory Bird Plan* that incorporates the results of consultation with the West Virginia Department of Natural Resources, Virginia Department of Game and Inland Fisheries (VDGIF), North Carolina Wildlife Resources Commission (NCWRC), and the Forest Service, and verify that no additional conservation measures will be required to minimize impacts on active rookeries. In addition, table A-1 of the revised plan shall incorporate the NCWRC's recommended updates to the North Carolina Birds of Conservation Concern list. The revised plan shall also include the Virginia Piedmont Forest

Block Complex, Allegheny Mountains Forest Block Complex, and the Southern Allegheny Plateau Forest Block Complex Important Bird Areas that would be crossed by the ACP and Supply Header projects in Virginia and West Virginia. *(Section 4.5.3.5)*

20. **As part of their Implementation Plans**, Atlantic and DETI shall file with the Secretary, for review and written approval by the Director of OEP, revised Master Waterbody Crossing tables for the ACP and Supply Header projects that address the recommended conditions in the identified column of appendix K of the EIS, and that include all National Rivers Inventory segments crossed. The revised table or accompanying filing shall document correspondence and input from the appropriate federal and state agencies regarding the updated information and any additional mitigation measures Atlantic and DETI will incorporate for each waterbody. *(Section 4.6.1)*

21. **As part of their Implementation Plans**, Atlantic and DETI shall file with the Secretary, for review and written approval by the Director of OEP, revised *Virginia Fish Relocation Plan, Freshwater Mussel Relocation Protocol for ACP in North Carolina*, and *North Carolina Revised Fish and Other Aquatic Taxa Collection and Relocation Protocol for Instream Activities*. These revised plans and protocols shall include notification to the appropriate federal and/or state agencies should an invasive aquatic species be observed or collected during relocation efforts; and, in consultation with the appropriate federal and/or state agency, identify the mitigation measures that Atlantic and DETI will implement at the crossing location if invasive aquatic species are observed. *(Section 4.6.4)*

22. **As part of their Implementation Plans**, Atlantic and DETI shall file with the Secretary, for review and written approval by the Director of OEP, an aquatic invasive species protocol for West Virginia mussel relocation efforts on both the ACP and Supply Header projects. *(Section 4.6.4)*

23. **As part of their Implementation Plans**, Atlantic and DETI shall file with the Secretary, for review and written approval by the Director of OEP, a final *Timber Removal Plan* that:

    a. incorporates the recommendations included in the Virginia Department of Environmental Quality's (VDEQ) letter dated April 6, 2017 (Accession No. 20170406-5489);

    b. updates the construction schedule discussion; and

    c. updates all time of year restrictions (TOYR) related to migratory birds and special status species for tree clearing. *(Section 4.8.1.1)*

24. **As part of their Implementation Plans**, Atlantic and DETI shall file with the Secretary, for review and written approval by the Director of OEP, finalized site-specific *Timber Extraction Plans*. *(Section 4.8.1.1)*

25. **As part of their Implementation Plans**, Atlantic and DETI shall file with the Secretary, for review and written approval by the Director of OEP, final site-specific *Residential Construction Plans* for all residences within 50 feet of the construction work areas identified after issuance of the draft EIS (including the residence at AP-1 milepost [MP] 169.4). *(Section 4.8.3)*

Conditions 26 through 50 apply only to Atlantic and shall be addressed <u>as part of Atlantic's Implementation Plan</u>. Condition No. 37 also includes a condition that shall be addressed <u>during construction.</u>

26. **As part of its Implementation Plan**, Atlantic shall file with the Secretary, for review and written approval by the Director of OEP, the results of the fracture trace/lineament analysis utilizing remote sensing platforms (aerial photography and LiDAR), along with the results of existing dye trace studies. Atlantic shall provide the results of this analysis on a composite map(s), illustrating surficial karst features with the potential for intersecting shallow interconnected karst voids and cave systems over a wide area; specifically, between the pipeline and nearby water receptors (i.e., public water supply wells, municipal water supplies, private wells, springs, caves systems, and surface waters receiving discharge). *(Section 4.1.2.3)*

27. **As part of its Implementation Plan,** Atlantic shall consult with the Virginia Department of Conservation and Recreation (VDCR) to determine if the route alignment and construction activities will impact the Burnsville Cove Cave Conservation Site. Atlantic shall file with the Secretary, for review and written approval by the Director of OEP, the results of its consultations, along with any proposed construction modifications or alignment shifts to avoid impacts on this site. *(Section 4.1.2.3)*

28. **As part of its Implementation Plan,** Atlantic shall conduct a data review and field survey of potential karst features in Augusta County, Virginia between AP-1 MPs 106.8 and 110, and file this information with the Secretary, along with any mitigation measures, for review and written approval by the Director of OEP. *(Section 4.1.2.3)*

29. **As part of its Implementation Plan**, Atlantic shall file with the Secretary, for review and written approval by the Director of OEP, a revised *Karst Terrain Assessment Construction, Monitoring, and Mitigation Plan* that includes

monitoring of all potential karst areas for subsidence and collapse using LiDAR monitoring methods during years 1, 2, and 5 following construction. *(Section 4.1.2.3)*

30. **As part of its Implementation Plan,** Atlantic shall file with the Secretary, for review and written approval by the Director of OEP, updated site-specific crossing plans for major waterbody crossings. The plans shall include, as necessary, the location of temporary bridges and bridge type, appropriate cofferdam locations, water discharge structure locations, pump locations, and agency-imposed TOYR and construction and restoration requirements. *(Section 4.3.2.2)*

31. **As part of its Implementation Plan,** Atlantic shall file with the Secretary, for review and written approval by the Director of the OEP, site-specific plans to minimize and mitigate impacts on the waterbodies that will be impacted at the Blue Ridge Parkway (BRP)/Appalachian National Scenic Trail (ANST) horizontal directional drill (HDD) entry and exit workspaces. Final plans shall be developed in consultation the U.S. Army Corps of Engineers and/or appropriate state agency(s). *(Section 4.3.2.6)*

32. **As part of its Implementation Plan**, Atlantic shall file with the Secretary, for review and written approval by the Director of OEP, a site-specific plan for the water impoundment structure at Jennings Branch (AP-1 MP 129.1), or identify an alternative location for the structure. *(Section 4.3.2.7)*

33. **As part of its Implementation Plan**, Atlantic shall file with the Secretary, for review and written approval by the Director of OEP, a revised *Restoration and Rehabilitation Plan* that incorporates recommended mitigation measures and seed mixes for Seneca State Forest based on consultation with the West Virginia Division of Forestry. *(Section 4.4.2.1)*

34. **As part of its Implementation Plan**, Atlantic shall file with the Secretary, for review and written approval by the Director of OEP, and the Forest Service for review and concurrence, detailed mapping of the existing conditions and proposed improvements to access road 36-016.AR1, including digital data, a description of the construction and operation impacts, including impacts on the adjacent vegetation communities, potential pond crossings identified in appendix K of the EIS, George Washington National Forest (GWNF) locally rare species located downslope, and identify the conservation measures that will be implemented to mitigate potential impacts. *(Section 4.4.7)*

35. **As part of its Implementation Plan**, Atlantic shall file with the Secretary, for review and written approval by the Director of OEP, a hydrofracture potential analysis for the Neuse River (AP-2 MP 98.5). If the potential for hydrofracture is

low, Atlantic shall utilize the HDD method at this crossing to reduce potential impacts on ESA-listed, proposed, and/or under review species. If the HDD method is not feasible, Atlantic shall consult with the U.S. Fish and Wildlife Service (FWS) and NCWRC to identify additional conservation measures that Atlantic will implement at this crossing to mitigate for the potential impacts on ESA-listed, proposed, and or under review species. *(Section 4.7.1.8)*

36. **As part of its Implementation Plan**, Atlantic shall file with the Secretary, for review and written approval by the Director of OEP, a hydrofracture potential analysis for the Nottoway River (AP-1 MP 260.7). If the hydrofracture potential is low, Atlantic shall utilize the HDD method at this crossing to reduce potential impacts on ESA-listed, proposed, and/or under review species. If the HDD method is not feasible, Atlantic shall consult with the FWS and VDGIF to identify additional conservation measures that Atlantic will implement at this crossing to mitigate for the potential impacts on ESA-listed, proposed, and/or under review species. *(Section 4.7.1.10)*

37. **As part of its Implementation Plan,** Atlantic shall file revised Carolina madtom habitat assessments based on 2017 surveys and consultations with the FWS North Carolina Field Office. This information shall also be incorporated into the ACP Master Waterbody Crossing table. **During construction**, Atlantic shall assume presence of the Carolina madtom where there is suitable habitat and implement the *North Carolina Revised Fish and Other Aquatic Taxa Collection and Relocation Protocol for Instream Construction Activities*, as well as the FWS' enhanced conservation measures for ESA sensitive waterbodies as defined in section 4.7.1 of the EIS. *(Section 4.7.1.11)*

38. **As part of its Implementation Plan**, Atlantic shall file with the Secretary the results of consultation with the VDGIF regarding in-stream construction activities proposed during the Roanoke logperch VDGIF TOYR at Waqua Creek and Sturgeon Creek. Documentation shall include any additional conservation measures required by VDGIF, which shall also be incorporated into the final ACP Master Waterbody Crossing table for each waterbody. *(Section 4.7.4.2)*

39. **As part of its Implementation Plan**, Atlantic shall file with the Secretary the results of consultation with the VDGIF regarding in-stream construction activities proposed during the VDGIF TOYR for green floater in waterbodies where presence has been assumed for this species (see appendix K of the EIS), in addition to in-stream construction activities proposed at Sturgeon Creek during the VDGIF TOYR for Atlantic pigtoe and dwarf wedgemussel. Documentation shall include any additional conservation measures required by the VDGIF, which shall also be incorporated into the final ACP Master Waterbody Crossing table for each waterbody. *(Section 4.7.4.2)*

40. **As part of its Implementation Plan**, Atlantic shall file with the Secretary, for review and written approval by the Director of OEP, a site-specific *Organic Farm Protection Plan* for the certified organic farms affected by the ACP Project, including (but not limited to) the milk and corn farm crossed between AP-1 MPs 141.8 and 142.4; the certified organic hog farm crossed between AP-2 MPs 118.8 and 118.9; and any additional certified organic farms not previously identified prior to construction. *(Section 4.8.1.1)*

41. **As part of its Implementation Plan**, Atlantic shall file a final copy of its *Haul Plan*, which will address transportation of equipment, materials, and personnel along narrow public roads in steep terrain. *(Section 4.8.1.4)*

42. **As part of its Implementation Plan**, Atlantic shall identify by milepost the locations where it will adopt a narrowed right-of-way to reduce impacts on forest land within the Seneca State Forest, and identify the locations of corresponding additional temporary workspace (ATWS). Atlantic shall also provide updated and reduced construction impacts information for all applicable resources (land use, wetlands, soils, vegetation, cultural resources, etc.) affected by the changes to construction right-of-way and ATWS. *(Section 4.8.5.1)*

43. **As part of its Implementation Plan**, Atlantic shall file with the Secretary, for review and written approval by the Director of OEP, a finalized *Contaminated Media Plan* that considers the recommendations included in the VDEQ's letter dated April 6, 2017 (Accession No. 20170406-5489). As appropriate, provide evidence of consultations with the VDEQ regarding its comments on the *Contaminated Media Plan*. *(Section 4.8.7)*

44. **As part of its Implementation Plan**, Atlantic shall file with the Secretary, for review and written approval by the Director of OEP, site-specific visual mitigation measures for each scenic byway developed in consultation with the DOT, Federal Highway Administration, West Virginia Department of Transportation, Virginia Department of Transportation, VDCR, and North Carolina Department of Transportation. Atlantic shall also provide documentation of agency consultation. *(Section 4.8.8.2)*

45. **As part of its Implementation Plan**, Atlantic shall identify mitigation measures, for review and written approval by the Director of OEP, to reduce the impacts on the Fenton Inn at approximately AP-1 MP 158.7 resulting from lighting equipment needed to support the HDD of the BRP and the ANST. *(Section 4.8.8.2)*

46. **As part of its Implementation Plan**, Atlantic shall file with the Secretary the locations where it will adopt a narrowed right-of-way to reduce impacts on forest

land and ecologically sensitive areas within the Monongahela (MNF) and GWNF, along with the locations of corresponding ATWS. *(Section 4.8.9.1)*

47. **As part of its Implementation Plan**, Atlantic shall file with the Secretary a revised trail, road, and railroad crossing table that lists the final crossing method that it will implement at each trail, road, and railroad. The crossing method at trails and roads on the GWNF shall be developed in consultation with GWNF staff. *(Section 4.8.9.1)*

48. **As part of its Implementation Plan**, Atlantic shall, if a bore or HDD crossing is not feasible, file with the Secretary, for review and written approval by the Director of OEP, site-specific crossing plans that identify the location(s) of a detour, public notification, signage, and consideration of avoiding days of peak usage for each trail and road affected by the ACP Project on the GWNF. The crossing plans shall be developed in consultation with GWNF staff. *(Section 4.8.9.1)*

49. **As part of its Implementation Plan**, Atlantic shall file with the Secretary, for review and written approval by the Director of OEP, a final site-specific HDD crossing plan and an alternative direct pipe crossing plan for the BRP. Provide documentation that Atlantic has consulted with the National Park Service (NPS) regarding both of these plans and adopted or addressed any substantive comments from the NPS into these plans. *(Section 4.8.9.1)*

50. **As part of its Implementation Plan**, Atlantic shall file with the Secretary aerial photographs depicting the entry and exit sites for the proposed Interstate 79 and Route 58 HDDs. The aerials shall identify any noise-sensitive areas (NSAs) within 0.5 mile of the entry/exit sites for each HDD or clearly demonstrate that there are no NSAs within 0.5 mile of the entry/exit sites. *(Section 4.11.2.2)*.

Conditions 51 through 56 apply to both Atlantic and DETI and shall be addressed <u>before construction is allowed to commence.</u>

51. **Prior to construction**, Atlantic and DETI shall file with the Secretary:

    a. all outstanding geotechnical studies for sites SL024, SS018, SL235, and SL239; geohazard analysis field reconnaissance of the 25 sites on the AP-1 mainline and 5 sites on the TL-635 loopline (as well as any additional geotechnical studies proposed following completion of site reconnaissance of these sites); and any mitigations proposed following the geotechnical studies and geohazard analysis field reconnaissance; and

b. status of the Best in Class Steep Slope Management Program analysis related to the ACP and Supply Header projects. *(Section 4.1.4.2)*

52. **Prior to construction**, Atlantic and DETI shall complete the remaining field surveys for wells and springs within 150 feet of the construction workspace, and within 500 feet of the construction workspace in karst terrain, and file the results, including type and location, with the Secretary. *(Section 4.3.1.5)*

53. **Prior to construction**, Atlantic and DETI shall file with the Secretary a copy of its final wetland mitigation plans and documentation of U.S. Army Corps of Engineers approval of the plans. *(Section 4.3.3.8)*

54. Atlantic and DETI **shall not begin construction of the proposed facilities until:**

    a. all outstanding biological surveys are completed;

    b. the FERC staff complete any necessary section 7 consultation with the FWS; and

    c. Atlantic and DETI have received written notification from the Director of OEP that construction and/or use of mitigation (including implementation of conservation measures) may begin. *(Section 4.7.1)*

55. **Prior to construction and upon completion of 2017 surveys**, Atlantic and DETI shall file with the Secretary and FWS the total acreages of:

    a. northern long-eared bat occupied habitat that will be impacted by the ACP and Supply Header projects; and

    b. northern long-eared bat suitable habitat that will be impacted by the ACP and Supply Header projects. *(Section 4.7.1.4)*

56. Atlantic and DETI shall **not begin** construction of the ACP and Supply Header projects facilities or use of contractor yards, ATWS, or new or to-be-improved access roads **until:**

    a. Atlantic files with the Secretary documentation of communications with the Lumbee Indian Nation, Coharie Tribal Council, Haliwa-Saponi Tribe, and the Meherrin Tribe regarding traditional tribal sites, including natural resources gathering locations in the project area;

    b. Atlantic and DETI file with the Secretary:

i. all survey reports, evaluation reports, reports assessing project effects, and site treatment plans, and cemetery avoidance treatment plans;

ii. comments on all reports and plans from the Pennsylvania, West Virginia, Virginia, and North Carolina SHPOs, the MNF, GWNF, and NPS, as well as any comments from federally recognized Indian tribes, and other consulting parties, as applicable; and

iii. revised *Unanticipated Discovery Plans* that include tribal contact information for those tribes that request notification following post-review discovery of archaeological sites, including human remains, during project activities;

c. the ACHP is afforded an opportunity to comment if historic properties will be adversely affected; and

d. the FERC staff reviews and the Director of OEP approves the cultural resources reports and plans, and notifies Atlantic and DETI in writing that treatment plans/mitigation measures (including archaeological data recovery) may be implemented and/or construction may proceed.

All material filed with the Commission that contains **location, character, and ownership** information about cultural resources must have the cover and any relevant pages therein clearly labeled in bold lettering "**CUI//PRIV – DO NOT RELEASE**." *(Section 4.10.7)*

Condition 57 applies only to DETI and shall be addressed <u>before construction is allowed to commence.</u>

57. **Prior to construction**, DETI shall continue to consult with the Westmoreland Conservancy regarding a route variation to minimize impacts on conservation easements, and shall file with the Secretary documentation regarding the results of its consultations and any proposed route modifications. *(Section 3.4.2)*

Conditions 58 through 60 apply only to Atlantic and shall be addressed <u>before construction is allowed to commence.</u>

58. Atlantic shall incorporate the Butterwood Creek Route Variation into its final route for the ACP Project. **Prior to construction**, Atlantic shall file with the Secretary the results of all environmental surveys, an updated 7.5-minute U.S. Geological Survey topographic quadrangle map, and a large-scale alignment sheet that illustrates this route change. *(Section 3.4.4)*

59. **Prior to construction**, Atlantic shall file with the Secretary documentation of concurrence from the VDEQ that the ACP Project is consistent with the Coastal Zone Management Act. *(Section 4.8.6)*

60. **Prior to construction within the Emporia Powerline Bog and Handsom-Gum Powerline Conservation Sites,** Atlantic shall:

    a. complete hydrologic studies using methodologies developed in conjunction with the Virginia Department of Conservation and Recreation; and

    b. develop in conjunction with the Virginia Department of Conservation and Recreation construction and restoration measures to avoid or minimize hydrology impacts on the sites for review and written approval by the Director of OEP.

Condition 61 applies to both Atlantic and DETI and shall be addressed <u>during construction.</u>

61. **During construction**, to minimize potential impacts of water withdrawals on ESA-listed, proposed, and under review species, Atlantic and DETI shall limit water withdrawal to not exceed 10 percent of instantaneous flow at ESA sensitive waterbodies identified in appendix K of the EIS. *(Section 4.7.1)*

Conditions 62 through 67 apply only to Atlantic and shall be addressed <u>during construction</u>, or <u>before specific construction activities are allowed to commence.</u>

62. **Prior to construction, but following tree clearing**, Atlantic shall file with the Secretary, for review and written approval by the Director of OEP, the results of the electrical resistivity imaging (ERI) studies along with any proposed construction modifications or alignment shifts to avoid impacts on Mingo Run and the Simmons-Mingo cave system. *(Section 4.1.2.3)*

63. **Prior to completing any geotechnical boring in karst terrain**, Atlantic shall file with the Secretary verification that it consulted with VDCR karst protection personnel regarding each geotechnical boring and shall follow the Virginia Cave Board's "Karst Assessment Standard Practice" for land development when completing the borings. *(Section 4.1.2.3)*

64. **Prior to construction, but following tree clearing**, Atlantic shall:

a. conduct ERI and/or air track drilling surveys of karst features identified within the construction workspace that are located within 5 miles of known or survey-identified bat hibernacula;

b. file a report(s) documenting these surveys with the Secretary and the appropriate federal and state agencies; and

c. if data suggests that construction activities have the potential to impact subsurface karst features that are connected to downstream bat hibernacula and/or the Madison Cave isopod suitable habitat (based on the ERI and/or air track drilling surveys), Atlantic shall consult with the FERC staff, FWS, and VDCR, and other appropriate federal and/or state agencies to develop the appropriate site-specific mitigation measures to avoid potential impacts on these species and their habitat. *(Section 4.7.1)*

65. **If the candy darter is proposed or listed during the life of the ACP Project**, Atlantic shall assume presence of the candy darter within Knapp Creek, Clover Creek, Glade Run, Thomas Creek, and the Greenbrier River, and apply the FWS' enhanced conservation measures for aquatic species outlined in section 4.7.1 of the EIS to these waterbodies, and any perennial tributaries within 1 mile of these crossing locations to minimize impacts on this species (see appendix K of the EIS). *(Section 4.7.1.12)*

66. **Prior to construction, but following tree clearing**, Atlantic shall:

a. conduct ERI and/or air track drilling surveys of the karst features identified during 2017 karst surveys that are within the construction workspace within the Madison Cave isopod priority area, including along proposed access roads;

b. file a report(s) documenting these surveys with the Secretary, and the appropriate federal and state agencies; and

c. if data suggests that construction activities have the potential to impact subsurface karst features that are connected to downstream Madison Cave isopod suitable habitat (based on the ERI and/or air track drilling surveys), Atlantic shall consult with the FERC staff, FWS, and VDCR, and other appropriate federal and/or state agencies to develop the appropriate site-specific mitigation measures to avoid potential impacts on this species and its habitat. *(Section 4.7.1.13)*

67. Atlantic shall file in the **weekly construction status reports** the following for NSA S9, the Gatehouse, and the office building near BRP; the Route 17 HDD entry and exit sites; and NSAs S11, S13, and S14 near the Swift Creek entry site:

    a. the noise measurements from these NSAs, obtained at the start of drilling operations;

    b. the noise mitigation that Atlantic implemented at the start of drilling operations; and

    c. any additional mitigation measures that Atlantic will implement if the initial noise measurements exceeded an L_{dn} of 55 decibels on the A-weighted scale (dBA) at the nearest NSA and/or increased noise is greater than 10 dBA over ambient conditions. *(Section 4.11.2.2)*

Condition 68 applies to both Atlantic and DETI, and shall be addressed <u>after construction.</u>

68. Atlantic and DETI shall offer to conduct, with the landowner's permission, **post-construction** water quality tests, using the same parameters used in the preconstruction tests, for all water supply wells and springs within 150 feet of the construction workspace and within 500 feet of the construction workspace in karst terrain. *(Section 4.3.1.7)*

Conditions 69 and 70 apply to only DETI and shall be addressed <u>after construction</u> or <u>during operation of the facilities.</u>

69. DETI shall file a noise survey with the Secretary **no later than 60 days** after placing the JB Tonkin Compressor Station in service. If a full load condition noise survey of the entire station is not possible, DETI shall instead file an interim survey at the maximum possible horsepower load and file the full load survey **within 6 months**. If the noise attributable to the operation of all of the equipment at the JB Tonkin Compressor Station under interim or full horsepower load conditions exceeds existing levels at NSAs S10, S11, S12, and S14 or 55 dBA L_{dn} at any other nearby NSAs, DETI shall file a report on what changes are needed and shall install the additional noise controls to meet the level **within 1 year** of the in-service date. DETI shall confirm compliance with the above requirements by filing a second noise survey with the Secretary **no later than 60 days** after it installs the additional noise controls. *(Section 4.11.2.2)*

70. DETI shall file a noise survey with the Secretary **no later than 60 days** after placing each of the Crayne and Mockingbird Hill Compressor Stations in service. If a full load condition noise survey of the entire station is not possible, DETI shall instead file an interim survey at the maximum possible horsepower load and file

the full load survey **within 6 months**. If the noise attributable to the operation of all of the equipment at the Crayne and Mockingbird Hill Compressor Stations under interim or full horsepower load conditions exceeds 55 dBA L_{dn} at any nearby NSAs, DETI shall file a report on what changes are needed and shall install the additional noise controls to meet the level **within 1 year** of the in-service date. DETI shall confirm compliance with the 55 dBA L_{dn} requirement by filing a second noise survey with the Secretary **no later than 60 days** after it installs the additional noise controls. *(Section 4.11.2.2)*

Conditions 71 and 72 apply to only Atlantic and shall be addressed <u>after construction</u> or <u>during operation of the facilities.</u>

71. **Following construction**, Atlantic shall replant long-leaf pine within the ATWS and the temporary construction workspace along the ACP Project route, and outside the 50-foot-wide permanent right-of-way, where it was cleared for construction. Based on Atlantic's May 1, 2017 supplemental filing, long-leaf pine-wire grass communities occur between AP-2 MPs 156.5 and 156.9. *(Section 4.7.1.5)*

72. Atlantic shall file a noise survey with the Secretary **no later than 60 days** after placing each of the ACP Project compressor stations in service. If a full load condition noise survey is not possible, Atlantic shall instead file an interim survey at the maximum possible horsepower load and file the full load survey **within 6 months**. If the noise attributable to the operation of all of the equipment at any station under interim or full horsepower load exceeds 55 dBA, L_{dn} at any nearby NSA, Atlantic shall file a report on what changes are needed and shall install the additional noise controls to meet the level **within 1 year** of the in-service date. Atlantic shall confirm compliance with the 55 dBA L_{dn} requirement by filing a second noise survey with the Secretary **no later than 60 days** after it installs the additional noise controls. *(Section 4.11.2.2)*

Condition 73 was developed after issuance of the final EIS, applies only to Atlantic, and shall be addressed <u>as part of Atlantic's Implementation Plan.</u>

73. **As part of its Implementation Plan and prior to construction**, Atlantic shall file with the Secretary, for review and written approval of the Director of OEP, a Mining Area Construction Plan that includes specific mitigation measures that it will use in areas of active or planned mining and that addresses issues related to mine subsidence and safe construction. Atlantic's Mining Area Construction Plan shall include documentation of its consultation with Western Pocahontas Properties (WPP) **including site-specific route deviations, as appropriate,** to resolve the concerns of WPP.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Atlantic Coast Pipeline, LLC	Docket Nos.	CP15-554-000 CP15-554-001
Dominion Transmission, Inc.		CP15-555-000
Atlantic Coast Pipeline, LLC Piedmont Natural Gas Company, Inc.		CP15-556-000

(Issued October 13, 2017)

LaFLEUR, Commissioner *dissenting*:

With the increasing abundance of domestic natural gas, the Commission plays a key role in considering applications for the construction of natural gas infrastructure to support the delivery of this important fuel source. Under the Certificate Policy Statement, which sets forth the Commission's approach to evaluating proposed projects under Section 7 of the Natural Gas Act, the Commission evaluates in each case whether the benefits of the project as proposed by the applicant outweigh adverse effects on existing shippers, other pipelines and their captive customers, landowners, and surrounding communities.[1] For each pipeline I have considered during my time at the Commission, I have tried to carefully apply this standard, evaluating the facts in the record to determine whether, on balance, each individual project is in the public interest.[2] Today, the Commission is issuing orders that authorize the development of the Mountain Valley Pipeline Project/Equitrans Expansion Project (MVP) and the Atlantic Coast Pipeline Project (ACP). For the reasons set forth herein, I cannot conclude that either of these projects as proposed is in the public interest, and thus, I respectfully dissent.

Deciding whether a project is in the public interest requires a careful balancing of

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[1] *Certification of New Interstate Natural Gas Pipeline Facilities*, 88 FERC ¶ 61,227 (1999) (Certificate Policy Statement), *order on clarification*, 90 FERC ¶ 61,128, *order on clarification*, 92 FERC ¶ 61,094 (2000); 15 U.S.C. 717h (Section 7(c) of the Natural Gas Act provides that no natural gas company shall transport natural gas or construct any facilities for such transportation without a certificate of public convenience and necessity.).

[2] *See Millenium Pipeline Company, L.L.C.*, 140 FERC ¶ 61,045 (2012) (LaFleur, Comm'r, *dissenting*).

the need for the project and its environmental impacts. In the case of the ACP and MVP projects, my balancing determination was heavily influenced by similarities in their respective routes, impact, and timing. ACP and MVP are proposed to be built in the same region with certain segments located in close geographic proximity. Collectively, they represent approximately 900 miles of new gas pipeline infrastructure through West Virginia, Virginia and North Carolina, and will deliver 3.44 Bcf/d of natural gas to the Southeast. The record demonstrates that these two large projects will have similar, and significant, environmental impacts on the region. Both the ACP and MVP cross hundreds of miles of karst terrain, thousands of waterbodies, and many agricultural, residential, and commercial areas. Furthermore, the projects traverse many important cultural, historic, and natural resources, including the Appalachian National Scenic Trail and the Blue Ridge Parkway. Both projects appear to be receiving gas from the same location, and both deliver gas that can reach some common destination markets. Moreover, these projects are being developed under similar development schedules, as further evidenced by the Commission acting on them concurrently today.[3] Given these similarities and overlapping issues, I believe it is appropriate to balance the collective environmental impacts of these projects on the Appalachian region against the economic need for the projects. In so doing, I am not persuaded that both of these projects as proposed are in the public interest.

I am particularly troubled by the approval of these projects because I believe that the records demonstrate that there may be alternative approaches that could provide significant environmental advantages over their construction as proposed. As part of its alternatives analysis, Commission staff requested that ACP evaluate an MVP Merged Systems Alternative that would serve the capacity of both projects.[4] This alternative would largely follow the MVP route to deliver the capacity of both ACP and MVP in a single large diameter pipeline. Commission staff identifies significant environmental advantages of utilizing this alternative. For example, the MVP Merged Systems Alternative would be 173 miles shorter than the cumulative mileage of both projects individually. This alternative would also increase collocation with existing utility rights-of-way, avoid the Monongahela National Forest and the George Washington National Forest, reduce the number of crossings of the Appalachian National Scenic Trail and Blue Ridge Parkway, and reduce the amount of construction in karst topography. Commission staff eliminated this alternative from further consideration because it failed to meet the project's objectives, in particular that it would "result in a significant delay to the delivery of the 3.44 Bcf/d of natural gas to the proposed customers of both ACP and

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[3] ACP and MVP filed their applications for approval pursuant to section7(c) of the Natural Gas Act on September 18, 2015 and October 23, 2015, respectively.

[4] ACP Final Environmental Impact Statement (FEIS) at 3-6 – 3-9.

MVP"[5] due to the significant time for the planning and design that would be necessary to develop a revised project proposal.[6]

Similarly, in the MVP FEIS, Commission staff evaluated a single pipeline alternative to the MVP project that would utilize the proposed ACP to serve MVP's capacity needs.[7] While this alternative was found to have certain environmental disadvantages, such as the need for additional compression to deliver the additional gas, the EIS acknowledges that this alternative would "essentially eliminate all environmental impacts on resources along the currently proposed MVP route."[8]

I recognize that the two alternatives described above were eliminated from further consideration because they were deemed not to meet each project's specific stated goals. However, I believe that these alternatives demonstrate that the regional needs that these pipelines address may be met through alternative approaches that have significantly fewer environmental impacts.

While my dissents rest on my concerns regarding the aggregate environmental impacts of the proposed projects, particularly given the potential availability of environmentally-superior alternatives, I believe that the needs determinations for these projects highlight another issue worthy of further discussion.

The Commission's policy regarding evaluation of need, and the standard applied in these cases, is that precedent agreements generally are the best evidence for determining market need. When applying this precedent here, I believe there is an important distinction between the needs determinations for ACP and MVP. Both projects provide evidence of precedent agreements to demonstrate that these pipelines will be fully subscribed. ACP also provides specific evidence regarding the end use of the gas to be delivered on its pipeline. ACP estimates that 79.2 percent of the gas will be transported to supply natural gas electric generation facilities, 9.1 percent will serve residential purposes, 8.9 percent will serve industrial purposes, and 2.8 percent will serve

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[5] *Id.* at 3-9.

[6] Staff also found that this alternative would likely limit the ability to provide additional gas to the projects' customers, another of the stated goals for the original proposal. *Id.*

[7] MVP FEIS at 3-14.

[8] *Id.*

other purposes such as vehicle fuel.[9] In contrast, "[w]hile Mountain Valley has entered into precedent agreements with two end users … for approximately 13% of the MVP project capacity, the ultimate destination for the remaining gas will be determined by price differentials in the Northeast, Mid-Atlantic, and Southeast markets, and thus, is unknown."[10]

In my view, it is appropriate for the Commission to consider as a policy matter whether evidence other than precedent agreements should play a larger role in our evaluation regarding the economic need for a proposed pipeline project. I believe that evidence of the specific end use of the delivered gas within the context of regional needs is relevant evidence that should be considered as part of our overall needs determination. Indeed, the Certificate Policy Statement established a policy for determining economic need that allowed the applicant to demonstrate need relying on a variety of factors, including "environmental advantages of gas over other fuels, lower fuel costs, access to new supply sources or the connection of new supply to the interstate grid, the elimination of pipeline facility constraints, better service from access to competitive transportation options, and the need for an adequate pipeline infrastructure."[11] However, the Commission's implementation of the Certificate Policy Statement has focused more narrowly on the existence of precedent agreements.

I believe that careful consideration of a fuller record could help the Commission better balance environmental issues, including downstream impacts, with the project need and its benefits.[12] I fully realize that a broader consideration of need would be a change in our existing practice, and I would support a generic proceeding to get input from the

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[9] ACP FEIS at 1-3.

[10] *Mountain Valley Pipeline, LLC, Equitrans, L.P.*, 161 FERC ¶ 61,043 at FN 286 (October 13, 2017).

[11] *Certificate Policy Statement*, 88 FERC ¶ 61,227 at 61,744.

[12] I note that this approach would not necessarily lead to the rejection of more pipeline applications. Rather, it would provide all parties, including certificate applicants, the opportunity to more broadly debate and consider the need for a proposed project. This could, for example, support development of new infrastructure in constrained regions where there may be demand for new capacity, but barriers to the execution of precedent agreements that are so critical under the Commission's current approach. In such situations, evidence of economic need other than precedent agreements might be offered as justification for the pipeline.

regulated community, and those impacted by pipelines, on how the Commission evaluates need.[13]

I recognize that the Commission's actions today are the culmination of years of work in the pre-filing, application, and review processes, and I take seriously my decision to dissent. I acknowledge that if the applicants were to adopt an alternative solution, it would require considerable additional work and time. However, the decision before the Commission is simply whether to approve or reject these projects, which will be in place for decades. Given the environmental impacts and possible superior alternatives, approving these two pipeline projects on this record is not a decision I can support.

For these reasons, I respectfully dissent.

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Cheryl A. LaFleur
Commissioner

[13] *See also*, *National Fuel Gas Supply Corporation, Empire Pipeline, Inc.*, 158 FERC ¶ 61,145 (Bay, Comm'r, *Separate Statement*).

Document Content(s)